BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the Matter of:

SUMMER 2004 RELIABILITY WORKSHOP

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Renaissance Cleveland Hotel
24 Public Square
Cleveland, Ohio

Thursday, July 15, 2004

The above-entitled matter came on for hearing, pursuant to notice, at 9:11 a.m.

APPEARANCES:

Chairman Pat Wood III - FERC
Chairman Alan Schriber - PUCO
Commissioner Nora Brownell - FERC
Governor Bob Taft
Commissioner Ronda Fergus - PUCO
Alison Silverstein - FERC
Commissioner Suedeen Kelly - FERC

APPEARANCES (CONTINUED):

Clarence Rogers - PUCO
Jim Gallagher - New York PSC
William Bokram - Michigan PSC
Thomas Burgess - FirstEnergy
Scott Moore - AEP
Clair Moeller - Midwest ISO
Kerry Stroup - PJM
Van Wardlaw - TVA
Paul Barber - NERC
Commissioner Donald Mason - PUCO
Jeff Wright - FERC
Jeffrey Webb - Midwest ISO
Jimmy Glotfelty - DOE
David Cook - NERC
Michael McLaughlin - FERC
Daniel Larcamp - FERC

MR. WOOD: Good morning. I'm Pat Wood, Chairman of the Federal Energy Regulatory Commission. And on behalf of my colleague Nora Brownell, I would like to welcome you all to our workshop conference today here in Cleveland on the status of the reliability issues both locally in the region and across the country.

Throughout the day today we will be looking at issues not just related to last year's blackout in this part of the country, but also looking at a lot of the broader issues that are taking place across the midwestern United States region, and also across the entire country, the folks who support the attributes of electricity, which is its reliability.

We're honored to have here our patron, who is actually the man who inspired us to have the conference. As Commissioner Brownell and I were here visiting Governor Taft about six or eight weeks ago, the Governor suggested that we might want to do a public discussion about these issues just to kind of keep everybody on the same page, and assure them of the forward progress that we are making and which continues to be made. So I want to thank the Governor for his kind invitation.

One of the Governor's finest achievements was his appointment of Alan Schriber to the PUCO. Alan is a long-time friend and colleague. We've enjoyed working together both when I was on the same commission in Texas and Nora was on the same commission in Pennsylvania at the same time that Alan was appointed -- or the second time that Alan was pointed to the PUC of Ohio. So at this time, I would like to ask Alan for a few remarks.

MR. SCHRIBER: Thank you, Pat. And that's just how we rehearsed it. I appreciate it, I appreciate your comments very much.

Obviously, we're here today to talk about reliability. Reliability has been a huge issue, particularly for the last year. And while we will be talking about reliability, I do need to say that on a going-forward basis, once we have this situation with respect to reliability put behind us, there's another aspect. There's the economics of everything we do in electricity. That speaks to the economics of transmission, generation, everything else.

And like so many others, we in Ohio are concerned. We know how we've already gotten a lot of support from our FERC colleagues, and they're doing everything they can to move the ball forward so we can have a great market with respect to electricity, not just reliability. So there are two issues, reliability and the economics, which is something we will all continue to work on for quite a long time.

Last year, after August -- we all know what happened, of course. I just want to tell you that Governor Taft was as engaged, if not more so, than perhaps any other governor that I know of. He testified in Congress. I know that both Pat and Nora requested at one time to come to Ohio just to meet with the Governor because of the respect that they had for the Governor, and they know how engaged he is.

So it's my pleasure to introduce someone who really does understand the issues, who has been very engaged in the issues moving the ball forward in Ohio and elsewhere, Governor Bob Taft.

MR. TAFT: Thank you very much. Chairman Schriber, it's my honor to welcome all of you here to Cleveland and to the state of Ohio. If you're not from Ohio, we're especially honored to have you here today, and the weather we are enjoying today is what we enjoy 365 days of the year here in Cleveland and throughout Ohio, so come back often and visit us.

And I'm particularly delighted to welcome Chairman Wood back to our state and thank you, again, for coming, and Commissioner Brownell as well. We appreciate the fact that you and your colleagues have accepted our invitation to come to Ohio to focus on the reliability of electricity and the steps taken to avoid a reoccurrence of last summer's massive blackout.

I also want to thank the members of Ohio's Public Utilities Commission who are here with us today for your leadership and for your focus on this very important challenge.

And I want to recognize especially Chairman Schriber, not only for his leadership of the commission, but also for his excellent work as a member of the joint United States-Canadian task force that determined the causes of last August's blackout, assigned responsibility and made recommendations to prevent a reoccurrence.

Today's meeting, coming at the start of the peak-use summer months, is critical for our nation, and is both timely and important for Ohio families. On August 14th of last year, the unprecedented blackout left 50 million Americans and Canadians without power, and posed severe threats to public health and safety and to the economy of Ohio, other states and provinces and two nations.

At least 2 million Ohioans were without power, some for two days. And in Cleveland, that blackout led to a near catastrophic failure of the city's water system, leaving tens of thousands in the metropolitan area without safe drinking water, and rendering beaches unsafe for days due to sewage contamination.

The interruption of business activity resulted in the loss of millions of dollars of economic activity that was not fully recouped through private insurance and state or federal programs. One major Ohio company lost their steel-making capacity for more than a week because of the damage from the blackout. Above all, the blackout shook the confidence of Ohioans in the system that most take for granted.

So I want to commend you, Chairman Wood, and the members of the Federal Energy Regulatory Commission for the major role that you played after the blackout and the subsequent investigation, and your work with our PUCO to help them enforce order resulting from the blackout in Ohio.

The blackout report highlighted that inadequate tree trimming was a major cause for the power outages in Ohio, and I commend you for your efforts to collect vegetation control reports from utilities operating transmission lines, to forge and develop recommendations for vegetation management along those lines.

In addition, I want to commend the FERC for being a vigorous advocate for mandatory reliability standards for the transmission of electricity throughout the country, repeatedly calling on Congress to enact new energy legislation.

It has been almost a year since the blackout, yet the Congress has failed to act on legislation of tremendous importance to our nation's economy and to the health and safety of our citizens. The binational task force report, on which Chairman Schriber served, called for making transmission reliability standards mandatory and enforceable with penalties for noncompliance.

Last fall I testified before the U.S. House Committee on Energy and Commerce urging Congress to enact just such a requirement. And I do so again today. In view of what happened last summer, further delay in enacting mandatory reliability standards for the transmission of electricity is inexcusable and poses unacceptable risks to the people of Ohio and other parts of our nation.

I've also repeatedly expressed my support for FERC's plan for an effective empowered regional system that places direction and control of transmission with independent regional grid operators.

Last month I called a meeting with the chief electric utility executives in Ohio to receive an update on their efforts to improve electric reliability, and I know you will be hearing from their representatives this morning. They all assured me that they are doing all they can to maintain and upgrade our transmission lines and to avoid a repeat of last summer's blackout.

But we simply cannot be secure or fully confident of the availability of electricity where and when we need it until the Congress enacts fair and uniform standards that apply to every system in the country, and provides FERC with clear authority to establish a coherent, empowered regional system for the transmission of electricity.

So I want to thank you, Mr. Chairman, again, for coming to our state. We look forward to an excellent hearing today, and we look forward as well to working closely with you, both myself and our Public Utility Commission, to assure a safe and a reliable supply of electricity and energy for the people of our state for many, many years to come. Thank you.

MR. WOOD: Thank you. I want to thank you, Governor Taft, for your presence today. It means a lot to me, to Nora, all the members of the commission, and to all that are here that we have kicked off our conference to that. I know you're a busy man with a big state to run, so I wanted to thank you for coming, and again, with special appreciation.

MR. TAFT: Thank you so much. Thanks, Pat.

MR. WOOD: Our Commissioner Kelly was -- her plane was delayed, but she will be joining us later in the morning.

And we've got some other esteemed guests here that Al would like to introduce.

MR. SCHRIBER: I wanted to, and I failed to, I apologize, I wanted to finish introducing our other commissioners. We have Commissioner Ronda Fergus, Commissioner Clarence Rogers, Commissioner Don Mason, Judy -- I do not believe is here today -- but we appreciate your attendance.

MR. WOOD: At this time I'd like to turn over the emceeing of the rest of the day to Alison Silverstein, who has worked with me for nine years in various capacities, the most recent of which is the reliabilities arena at the FERC. And I appreciate, I want to say publicly, Alison, the hard work that you have done collaborating with all these hardworking folks in the industry to focus on solutions, not trying to affix blame, but trying to fix the problems.

And that's what the focus of today's conference is about, getting an updated report on how things are in this region of the country. And as I mentioned, we are going to talk broadly about what's going on nationally.

In the middle of the day, before we break for lunch, we will have Jeff Wright from our staff, who is sitting across from me, give a general infrastructure update, because I think it's helpful, as always, to put into context the broader issues which are a critical concern for our whole country. Just the actual fact-based status of the infrastructure in the Midwest. So we'll be doing that as well.

At this time I would like to turn over to Alison.

MS. SILVERSTEIN: Good morning.

Thank you all for coming. As others have said, the purpose for our session is to assure that the problems of August 2003 do not occur again. To that end, we have structured the bulk of the morning to address what has changed on the nation's electric grid in the Midwest for the past -- over the past 11 months. And we have a panel of representatives from all of the major entities that helped to work on, own or improve parts of the grid here with us.

I will simply read the title of each of the individuals and the company that he represents, and we'll just sail on down the list one at a time.

We're going to start with Tom Burgess, who is the Director of Energy Delivery Restructuring for FirstEnergy Service Company of Ohio. Tom? The Ohio portion of FirstEnergy, excuse me.

MR. BURGESS: Alison, Commissioners, I'm pleased to be here today. My name is Tom Burgess, and I'm the Director at FirstEnergy of Energy Delivery Restructuring.

The events of last year taught us a lot about how the transmission grid is being used today, and the many impacts that that can have on our system. As reinforced by the joint task force's final report on the August 14th power outage, competition in the electric industry has forced the grid to be used in ways for which it was not designed, making operations far more complex.

As an industry, and as the task force has recognized in its recommendations, we need to understand these comprehensive impacts that this has on providing reliable service.

Most of the recommendations made by the task force, as well as others who have reviewed the events of August 14th, focused on industry-wide problems, not issues specific to the individual utilities. Because these recommendations will lead to lasting improvements in the reliability of the overall grid, the entire industry needs to respond to them. At FirstEnergy, we're fully committed to helping enhance our part of the transmission grid.

We have taken a number of important steps towards that end, and are pleased to report that we've certified to the North

American Electric Reliability Council the completion of the various items that were related to the NERC readiness audit, the reliability recommendations, as well as the task force findings.

We further received verification of the completion status from a NERC team of experts which conducted an on-site review just last week. Collectively, we've learned many lessons about the reliability impacts and the operation actions that are necessary to address the different uses of the grid. Many of these have been reflected in the overall recommendations for the industry, and we seek to enhance overall grid reliability.

We support these objectives and are actively involved in these broad reliability initiatives, some of which I'll describe later this morning.

At this time, however, I would like to summarize some of the areas that we've endeavored to enhance reliability for our portion of the grid in anticipation of the summer 2004 conditions, as well as for the long term based on many of these lessons.

Through our commitment to achieving ongoing reliability objectives, we have enhanced training for our transmission operators. We have developed enhanced emergency operating response protocols, and we have participated in several joint regional drills. These and other steps better equip our transmission operators with the knowledge and the tools that they need to deal with the challenges related to how the grid is being used today.

We've also deployed a new ESCAT EMS computer system, which is providing the operators with enhanced functionality and sophisticated monitoring tools within our control centers that are located in Ohio and Pennsylvania. This system was planned, purchased and in development before the August outage last year.

We're further providing them with dynamic system visualization tools and extensive back-up control center capabilities. The EMS system used in our Ohio and Pennsylvania control centers is based on the same platform that is -- as the one used by our Ohio reliability coordinator, the Midwest Independent

Transmission System Operator, and it also enhances our interfaces with PJM.

We have established a training review committee to help ensure that we are continually meeting the training needs of our operators.

NERC has taken note of our advances in our operator training, and we're proud to have been named the "NERC-Approved Continuing Education Training Facility Provider." That means that other organizations can send their operators to our facility for training.

Additionally, under our vegetation management program, which is part of our operational preparedness plan, we have completed foot patrols of all of our 115-500 AV transmission rights-of-way in all three states in which we operate, and are conducting more comprehensive aerial patrols of those facilities. These protocols are important to our ongoing reliability efforts.

Our operational readiness efforts also have included confirmation and coordination of applicable system and regional limits. As part of that process, we've considered contingency conditions, extreme contingency conditions and mitigation plans. We've implemented interface capability guidelines for northern Ohio, and established guidelines for voltage and reactive reserves.

We applied conservative limits in operations as appropriate. Additionally, we have reaffirmed and coordinated our transmission line ratings with others in the region.

We've developed enhanced foliage procedures to train and help ensure the availability of reactive resources, those contained both in our substations as well as generation, including IPPs beyond our control area, as well as further ensuring that distribution line capacitors are available.

Organizationally, we have centralized heat/energy delivery operations to provide an even greater focus on reliability, standardized business practices and enhancement responsiveness. Through these and other important steps, we're well-positioned to comply on the customer demand for the summer and for the years ahead.

We're proud of the progress we've made today, and we're grateful for the support we continue to receive from ECAR, NERC, FERC and other agencies. The NERC technical assistance team, which included representatives from all three organizations, was instrumental in helping us address and ultimately verify completion of NERC's recommendations, those of the task force and the NERC audit report findings.

We believe the steps we've taken as a company and as an industry since the outage will go a long way to helping enhance reliability in our portion of the grid; however, we recognize that our work doesn't stop here. In fact, it's just beginning. We need to focus on the role the transmission operation should play in the new and evolving RTO and market environments in light of the increasing pressures on grid reliability.

While the steps we have undertaken are significant and incorporate the best ideas of the sophisticated assistance teams that refined and reviewed our operations, the issues we now face as an industry are much broader. They involve much more than actions by a single entity, and will require involvement of the entire industry to adequately ensure enhanced reliability for the long term.

To make really truly effective improvements, we must first acknowledge the current limitations of the system and recognize the need to maintain focus on major load customer reliability. The fact is that the grid was built to serve local load centers, and we cannot continue trying to make a system what it is not.

We're committed to advancing the reliability of the grid and encouraging others to participate. These efforts clearly need to expand as the reliability pressures are different, increasingly complex; and they're challenging from a technical standpoint.

Let me summarize a few examples. Reliability standards must address the changes that have come with competitive markets. New plants are being located based on opportunity near existing transmission lines, but far from the load centers they intend to serve. New single-unit control areas are being created while avoiding requirements to support the grid.

All generators need to be required to support the grid, to take action to maintain reliable service. Margins on the transmission system must be replaced as they were in the past. And we need to continue to study and better understand the grid's vulnerability to consequences of long-distance power transfers and the installation of new power plants.

Operators themselves need better tools and technology, including access to more real-time information so that they can react immediately as changing power flows, including loop flows. RTOs need to be organized in ways that enable them to provide the means to evaluate the availability and perform and encourage investment on the grid.

They must be required to effectively communicate with each other's systems when they take actions that could affect others. Electrically significant systems must be under the same reliability authority, and if that's not possible, very robust agreements with intra-RTO coordination must be in place.

Without reform, even the best performance standards will not reduce the risk of grid failure.

The issue of reactive power, the

electricity that supports voltage and allows transmission to occur must be broadly examined within the context of effectively operating a regional transmission grid while supporting large transactions. The grid needs sufficient supplies in reactive power, as well as other ancillary services necessary in a minute-to-minute or instantaneous basis.

A better means for scheduling power region to region needs to be developed immediately. Continuing to employ the contract path method -- model clearly undermines reliability.

Building on existing engineering practices. Key improvements can be advanced by providing detailed estimates of on-line retail, reactive power loads on a regional basis. Clearly there is a lot of work to be done in providing the tools, the software, the visualization capabilities that permit more effective and sophisticated real-time operations, and even anticipation of conditions, thereby providing greater operational margin.

The move to competitive markets has introduced new uses of the grid, but the incentives for investment have not changed. Incentives must be realized logically and in a transparent way with a focus on solutions. To ensure that effective incentives are in place with both buyers and sellers that act efficiently and responsibly, RTO government's policies may need to be reformed.

Without investments, the grid will not be able to keep pace with the demands that are being placed on it. That investment needs to be encouraged, clearly provide for both the new assets to support market interactions, as well as enhance the capability of the existing infrastructure.

It may even become practical to control the network operation, effectively relieving transmission bottlenecks and create adaptive or even self-healing integrated grids. Unless the regulatory system clarifies its controls, investors will not bring in capital to transmission. The more the grid is used in ways for which it was not designed, the greater risk we run of failures.

FirstEnergy is in a unique geographic location, and obviously plays an important role in advancing reliability and compatible competitive market operations. We're in a unique position within the grid between PJM, MISO, New York ISO and the Ontario IMO with respect to dynamic operations, market interactions, RTO integration, IPP development and the physical loop flow effects on our facilities.

We're in a unique position with operations within two of the largest functioning RTOs in the country, adjacent to large entities planning integration into RTOs, and within a major market unfolding within MISO. We're in a unique experience -- we have unique experience in dynamic power system interactions between four major market centers, as well as position along the largest seam between major RTOs.

As an industry, we must address these important issues to realize our goal on enhancing overall grid reliability. FirstEnergy is committed to that process, and by putting customers and reliability first, we're confident that as an industry, we can achieve that goal. Thank you for your attention.

MS. SILVERSTEIN: Thank you very

much, Mr. Burgess.

Commissioners of FERC and Ohio, if you have any questions for this speaker?

MR. WOOD: Mr. Burgess, you raised a lot of interesting points in your comments and I want to follow up on a couple.

Do you feel like in the last several months -- I'm referring actually to what looks like a pretty good report card for you guys that came out from NERC's recommendations verification team, either yesterday or the day before -- 14th. And in going through that, I just want to kind of understand better. Do you feel like the region will have visibility tools that are necessary to address some of these broader regional concerns available to you? And more importantly, are available to your reliability coordinator to effectively manage some of the obscurity between the different systems that come together here?

MR. BURGESS: I think that we have visualization tools that help us see farther into the grid, so that's an important additional ingredient. And we know that both ISO and PJM have similar tools; however, the long-distance power transactions that are present on the grid encourage us to enhance reliability. To enhance reliability, we need to have even greater tools available to the operators, better tools that allow them to understand the interactions that are occurring between RTOs or with some of these assistant RTOs.

MR. WOOD: You mentioned the interregional coordination --

MR. BURGESS: That's right.

MR. WOOD: -- other than -- the contract path, what is that? Is that the LMP method? What are you talking about there particularly? I'm just curious.

MR. BURGESS: Well, portions of PJM operate in the LMP environment, and that does provide for a way of managing transmission transactions or power transactions. In the Midwest ISO and other regions of the country, they are using contract path methodologies currently. Those have a lot of loop flow impacts.

And even to the extent that the Midwest ISO embraces an LMP model when their market unfolds, we have a period of time until that occurs that we are in both environments. And so those kinds of interactions need to be well understood, and we need to make sure that we're taking steps to minimize those interactions so that we can enhance reliability.

MR. WOOD: What particular negative implications happen where there -- where they aren't contract path on one side and LMP on the other?

MR. BURGESS: Well, one of the things that that presents is a loop flow for our parallel path problem. We have -- at FirstEnergy, we have been advocates of the -- we initiated an effort which was called the General Agreement on Parallel Paths previously, which the FERC endorsed, which was an experiment to try to better understand how to manage such parallel flows. But parallel flows were occurring from even distant locations, such as interactions between Ontario and New York causing parallel flows on our system, or within PJM, even though PJM is using an LMP environment.

MR. WOOD: And then the final

question, you mentioned something about the need for regulatory role clarification and RTO governance policies. Flesh it out a little bit for me. That's kind of on the front burner as we speak.

MR. BURGESS: Well, what we're suggesting --

MR. WOOD: Again, this was, I think, in the context of your suggestion that they need to visualize a more robust investment of the grid.

MR. BURGESS: Well, we think that there's a lot of opportunity for transmission investments that will create the kind of infrastructure that will facilitate these market transactions, once we well understand where the markets are occurring. And to accomplish these broad types of transmission investments, which perhaps would encompass more than a single state, or more than a single RTO, we need to have clarity about how we can make those, incentivise those enhancements and do so in the RTO context.

MR. WOOD: Is it a how-you're-going-to-get-your-money-back kind of question? I mean, do you invest $100 million to upgrade this transmission system, how do you actually get it paid back?

MR. BURGESS: That's part of it. Part of it has to do with making sure that the transmission is invested, is consistent with sending transparent pricing signals to the market, and that will provide the right signals so the generators are locating in the right locations within these markets.

MR. WOOD: Thank you.

MS. SILVERSTEIN: Other commissioners, any questions?

Our next speaker is Scott Moore, Vice-president, Transmission Operations for American Electric Power.

MR. MOORE: Good morning. Thank you Chairman Wood, Chairman Schriber, commissioners and Alison for giving me an opportunity to make a very brief presentation concerning what we have done since the blackout in preparation for summer operations.

Since August 14th -- August 14th's blackout was an eye opener for many in the industry, from the regulatory standpoints, from a technical standpoint in terms of NERC, its operational groups, its planning groups and for the public about the vulnerabilities and fragileness of our industry and infrastructure, and how a very small event can make such a dramatic impact on the economy.

And since the blackout, and all of the work that has been done by the joint DOE-Canadian task force in the blackout, the NERC investigation, the many investigations done by ECAR, and the internal investigations done by the utilities themselves, we have learned many lessons and have found many gaps in what we have in our industry and what we are doing with the infrastructure.

Some of the things that we have been able to accomplish concerning the NERC recommendations. There were 14 original recommendations from NERC which were then embodied in the final blackout report. There are three additional recommendations now affecting the industry.

But the one specifically that I would like to concentrate on has a direct impact on reliable operations for this summer. One, ADD-completed operator training requirements. We have put over 100 transmission and system operators in 140 hours of emergency operations training, which was incremental to the normal training that they have gone through. That's a significant amount of manhours to go through in training, and most of that was done on overtime, since it was not built into our work schedules prior to the blackout.

We had to, very quickly, put -- develop a program and put the operators through that program, and we accomplished that prior to the June 30th deadline.

Going on with the training, that's what we've done just for -- to meet the short-term requirements. The AEP has taken the initiative that we need to continue this effort, and we have expanded our training staff from three individuals to five full-time trainers just to train our system operators. And so we have done that. We have hired additional dispatchers so that we now have time in the work schedules to accomplish the amount of training.

And so to me, this is a tremendous effort that we've gone through, and a commitment ongoing to make sure that our operators are the best trained operators to do the job, not on a normal day-to-day basis, but when these emergencies arise, ensure that quick actions and correct actions be made to prevent a small event from cascading into a major blackout.

We're in the process of identifying control center visualization tools and software from various vendors. AEP has many tools at its disposal to see what's going on in the network. We have one of the best state estimators running, and had it running prior to the blackout. Since the blackout, we have beefed up that state estimator so that we give an exclusion once every minute. You are able to look at the condition of the system, what we call the state of the system.

Besides just speeding up the process, AEP has an increased model. We have, in the past, always looked at our system and some of the systems around us, but we have increased the size of our model to look at more of the systems around us that could have a potential impact on us.

Part of the rational for doing this

is the concept called defensive depth. PJM is our reliability coordinator, and they have the prime responsibility for maintaining the reliability of their footprint with many similar tools that we use. But they need a backup. And what we think is called defensive depth is that my operators need to be seeing the same information, the same conditions of the network that our liability coordinator and the other liability coordinators are seeing, because not necessarily will every reliability coordinator back at their desk see every event, because they're in such a large network. And even if they do see the same events, one, to have some assurance, some backup that that was going on, that you did get the correct information.

And so with our state estimation and with our tools, we're able to look into the AEP footprint and the networks around us, we'll have that defensive depth to back-up PJM and MISO and the other utilities in the Midwest region.

AEP tools go beyond the Midwest region and includes the Southwest Power Pool. And one of the findings of the readiness audit that AEP went through is that we should expand our model into the Southwest Power Pool. So part of our efforts in expanding our state estimator was to increase the models that we are looking at in the Southwest Power Pool for those utilities in that area.

One of the things that AEP recognized immediately after the blackout was that the communication and the coordination with the independent power produces was not as good as it should be. Basically, we had the reality that we would just let them connect to the system and run it the way they wanted, and basically, did not worry about good operation. Well, we see that that was not the correct attitude, and we -- even though we had rules in our interconnects basically to enforce better coordination, we did not enforce those rules. And so now we're doing that.

We have improved what we call our communications protocols with independent power producers, to make sure that we know what they're doing and they know what's going on in the networks as well. It's a two-way street of communication, because they are part of the network and they have both megawatts and megabars to provide for the support of the network. So we have improved those communication protocols.

As I mentioned before, AEP was one of the first control areas to go through the NERC readiness audits, and we successfully completed that audit with some very minor recommendations. And we have completed and implemented those recommendations that were found by the NERC readiness audit team.

It's not so much the findings that are important when you go through a readiness audit, it's what you learn as you go through the process, the preparation that you go through in answering the questions, the preparation that you go through to make sure your documentation is proper. The value that you get when third parties come in from across the industry with different paradigms on what they consider good operation, come in and actually share information -- because there was a two-way street with the auditors. You know, basically, they would see what we were doing, and then they would see -- tell us how they did it at their shops, as well as how the best practices can be seen. And so it was a very rich learning experience.

And it's not so much the recommendations and implementation of recommendations, but what you learn in going through the process. It is a very valuable tool that NERC has implemented, and I applaud NERC in doing what they have done and so quickly on such a large scale.

I would like to move forward a little bit on what we'll be doing in the near future. The AEP/PJM integration, which is scheduled to occur on October 1st of this year, where AEP will be integrated into the PJM marketplace.

We have been working on this for a number of years, and now we're getting down to the finish line. And as you look through what happened in the blackout, one of the things that you want to make sure of is that you're not only ready for the market, but you make sure that all of the reliability aspects are in place as you go into the new market. That's more important.

And some of the things that AEP/PJM are currently working on are developing the business rules between the AEP's local control center and PJM's control center. We are having numerous meetings to make sure that we share our operating guides, our emergency procedures. We're reviewing those face-to-face with PJM operators. We're making sure that lines of communications are there, that AEP can properly communicate with PJM, and that there's an understanding. Because it's more than just speaking, it's an understanding of the system, it's an understanding of what you mean when you say something. And so we're making sure those communications are in place.

And then we're reviewing all of the emergency operating procedures and the standard operating procedures so that PJM understands what we intend to do and we understand when they tell us to do something, what their expectation is of us. And so that's very important to get that done prior to being integrated into the market.

As I mentioned, we developed various communication protocols to ensure that we have good infrastructure and proper communication. And we do expect full integration on October 1, 2004.

System improvements. What have we done since the blackout to improve the system? Well, it's very difficult to make major improvements in the infrastructure and the transmission network in such a short period of time, but there are things that we can do, and things that we are hoping to have done may or may not work -- be accomplished.

But we have been improving the transfer capability by spending capital dollars to update transformation at strategic areas of the system. We have always looked at the system and done good planning of the system, but since the blackout, we've gone and made sure that those strategic areas, areas where there are bottlenecks in the system due to the changes in the market, due to what we have seen since the blackout, look at those strategic areas and make sure that we can change schedules to improve the transformation capability. Basically, installing transformers to improve the capability of the network to transfer the power.

We have done that and are continuing to do that to beef up those portions of the system and get the biggest bang for the dollar.

AEP expects to invest approximately $750 million per year in our T&P improvements system wide. That's an ongoing investment. $750 million is a tremendous amount of money to be going forward and it's a very large commitment on the part of AEP.

We've developed system-operating procedures for northwest Ohio to ensure we maintain adequate pre-contingency voltages in order to survive worst double-contingency events. Prior to the blackout we were generally more concerned about single-contingency events, and since the blackout, we have discovered that there are some double-contingency events that we need to pay attention to in the northwest Ohio area, where one facility is contingent on another facility. The loss of the other facility, but that facility was contingent on the loss of the first. It's a double contingency.

Some things we really weren't planning on prior to the blackout. Those things have now been studied, we have put procedures in place to monitor those facilities and make sure we can survive double contingencies.

More emphasis and efforts have been put on in the voltage and pre-contingency voltages to make sure that if with do have a double contingency, that the voltages won't drop to the point to cause collapse.

We have been performing system studies to maximum permissible transfers without jeopardizing voltage performance. Make sure that we have done those studies in advance that when transfers, large power transfers are occurring, the voltages stay at the accurate levels.

And with that, I would like to thank the commission for this opportunity for AEP to present, and answer any questions.

MS. SILVERSTEIN: Commissioners, any questions of Mr. Moore?

MR. SCHRIBER: Mr. Moore, maybe I missed it, but in your state estimator, what are the sources of your data? Is it widespread, or is it from the various ISOs, or is it regional or what?

MR. MOORE: For -- AEP has an estimating system that brings in the data off of our network. We then send that data to PJM in what's called the ISN, the intraregional security network. So that information is shared with PJM and MISO. We also then get data from the same network from facilities around us that we put into our state estimator so that we have it for ourselves as well as the utilities around us.

MR. SCHRIBER: It's all instantaneous?

MR. MOORE: I won't call it instantaneous because there is a delay in some of that data, just with the way communication protocols are written, and the delay can be 2 to 10 seconds. So our data, which normally comes in on a 2-second basis, the data from most utilities around us could be delayed up to 10 seconds.

MR. SCHRIBER: Is that a bad things thing that needs remedied?

MR. MOORE: No, it's not a bad thing. I don't think -- we really don't have the ability to speed that up. When you start sharing data between one utility and another, because we can't pull it for our use directly, and that's where we get the very fast data. We have to get the data after it has come into their EMS system, it's been processed and then it's sent out to others to share in that process. It takes time. And since we -- our computers speak different languages, it has to go through a conversion process, which also takes time. I view it as accurate.

MR. SCHRIBER: Thank you.

MS. SILVERSTEIN: Any other commissioner questions?

Commissioner Mason from Ohio.

MR. MASON: Thank you. I would be curious in the future of getting additional information on the breakdown of that 750 million per year capital improvement on the T&P and on a state level; but I don't expect you to carry that on a sheet of paper.

MR. MOORE: I'll take that up next time.

MR. MASON: Thank you.

MS. SILVERSTEIN: Any of the other Ohio commissioners? Thank you very much, Mr. Moore.

Our next speaker is Clair Moeller, Vice-President of St. Paul Operations for the

Midwest ISO. Mr. Moeller?

MR. MOELLER: Thank you. Mr. Burgess gave the first half of my talk, and Mr. Moore gave the second half of my talk. Being first is easier. So I'm going to move my comments a little bit from what, to a little bit how.

The most important thing we did to prepare for this summer, unfortunately, was have last summer. It clarified our thinking in several ways. The role that the Midwest ISO had anticipated as we designed the organization in collaboration with the transmission owners of the Midwest ISO, essentially, we looked to the historic risk-management practices of the industry that throughout -- the 1965 event, that had a very similar footprint. And that is what the risk-management strategies were that were in place and served the industry very well. And frankly, most of us did not see a need for change.

With the advent of FERC's order in 2000, the indications that we needed to become more vigilant and controlled more tightly, the interactions between utilities, that was the beginning of that conversation.

There was a cacophony of voices at that time trying to define specifically what the role of the Midwest ISO, or any RTO, should be. That event crystallized the thinking in our region, and provided us the opportunity to move from a town crier kind of role, which was the original role of the Midwest ISO, to more of a hospital, take a more active role in managing, actually managing the operation of the system. That's not an insignificant role shift. The town crier is not an easy job.

It's important to understanding the manageable operation of the system. It's fairly straightforward. You need to do risk recognition, you need to do risk mitigation. If events happen, you need to try to contain those events, and then, unfortunately, after the event, we need to do restoration.

So at its highest level, it's pretty straightforward, but there is a lot of important work in understanding those risks and what this mitigation really means.

An analogy that I would offer is it's not a lot different than how we as individuals seek to avoid being mugged. Okay? You look at, is this a risky place? Do I belong here? What are the risk factors? And you stay out of those places that are risky. Occasionally, you can get mugged at the Starbucks because a mugger doesn't know they don't belong there. Okay? But that's the reality of operations. It's just -- you know, driving a car would be another example. As you drive a car, you're always doing risk evaluation and taking actions to avoid those risks.

In the middle of that then, how do you manage those risks? There are important tools and philosophies that -- for moving forward. The Midwest ISO, we're moving to the LMP-style market. And what that provides is much more controllability of individual generators so that you can take -- interdict, if you will, interdictive actions in order to manage those risks. From a reliability side, that's what's important about the market.

To keep a reliable system absent those kinds of control tools, the simple way is to not use as much of the transmission system as we might in order to provide those back-up capacities at any given time. What the LMP market will do for us is it will allow us to understand on a five-minute interval where generators are, where they're going, and essentially be able to move them in order to manage the risk for that re- -- to do that reliable system.

Another part of our role has to do with assisting in the definition of what transmission should be appropriate. This is also a new place. In terms of how we define need historically for transmission systems, it's been from a generator or a central station-type generation. It's owned by someone to serve loads served by generally that same someone. There's a consortium of those type of things.

But that's been our definition of need. It's been a lights-on/lights-off definition, rather than, is this marketplace big enough to serve everyone reliably? So that movement in terms of need is an opportunity that we've begun in terms of trying to look at it from that position in a place where we are seeking collaboration, particularly of state commissions as we find that need, so that when we do propose that $750 million investment, it puts clear criteria around, this is valuable and it's valuable to not only a load, but it's valuable to the nation as a whole.

Another piece of our role is ensuring comparable access to the wholesale marketplace. And from my position, I view that access as also another control point where we handle risk. In historic times we would accept all transactions, and then we'd use the transmission loading procedure to try to unload the system, which is a little bit clumsy and not always very effective.

In today's marketplace, what we are seeking to do is recognize the parallel flows and stop the transaction before it starts in order to manage that risk of overloading the system. That's caused an economic turbulence that some of the commissioners may hear about from time to time, because if you allow those transactions and then curtail them, it's proactive. Where if you stop the next transaction, the sharing of that reduced use of the system is very different. So the last individual doesn't get any, rather than everybody sharing. And so there's a little turbulence around that, at least in the western part of the ISO. I hear about it on a fairly regular basis.

And then the last thing is to provide that transparency that we talked about earlier. We believe that the most important thing you can do is provide that transparency. Policy makers can't make good policy if there isn't complete access to all information and all analysis that's available.

After August 14th -- well, the 13th was pretty busy, and the 14th is like, 'Well, how are we going to make sure we don't do this again?" A bunch of initiatives started inside the Midwest ISO, as the study was being done and as NERC was preparing for their readiness audits, it was clear to us that we needed to increase the reliability tools which I would characterize as look-ahead tools.

The state estimator that the MISO has employed was in its kind of shakedown groups. It wasn't production, we were in shakedown, the organization, and at the time it was -- the model size was technically unprecedented; the biggest state estimator model that had been attempted. And that, you know, has its own challenges.

The important thing about the state estimator isn't so much the state estimator solution, as what to do with it. So that statement estimator solution -- and every utility and RTO that has one does this next step, and we call it contingency analysis, which is, very simply, a what-if game, where you ask the computer every time that you solve this data, you take a copy of it and put it over on the computer and you play what-if games with it.

In the case of Midwest ISO, we run 5,000, about, automatic scenarios, or what-if games. They're single contingency, double contingencies, and all of these things are done in collaboration with the utilities that we serve.

Visualization tools is the second step of that. As we try to maintain that understanding, the next thing you need to do is understand how the system was changed so that you can go back and reanalyze. That's the same kinds of visualization tools that Mr. Burgess talked about, we've employed. The NERC readiness audits confirmed that these needed to be checked, and it's technically very, very similar to the presentations you've heard before.

Operator training. That was, again, out of that same series of studies of NERC audits. We do have an operating simulator. We're still building additional scenarios.

It's important to simulate events, it's important to do those walkthroughs of the most risky events so that all the operators both at the RTO level and at the control area level are exercised in how to do that.

Communication protocols. You know, this was a simple thing to solve, but it was an unfortunate thing that we learned, is that the people were just sloppy in their verbal communications. You didn't know for sure who you were talking to. Which control room was it? Like I say, it was an easy thing to solve, but it was a pretty important one to solve as well.

Operating agreements is probably the last thing. In terms of operating agreements in the Midwest ISO audit, there's a set of partial requirements with customers in the western region that have some kind of complicated and convoluted agreements in place, and it wasn't clear to those control areas that the Midwest ISO indeed did have reliability authority to direct their action. We have since cleared that up.

The other thing that we're working on, and continue to work on, are seam agreements. The first seam agreement that we executed was between Midwest ISO and PJM. That's a very important seam agreement. As talked about earlier, there's a lot of energy loops between us. That's particularly true now that we kind of leapfrog each other.

And that was a very good protocol that was constructed there. We have taken that protocol and we are in discussions with TVA, SPP and the vast community to take that same protocol and use it everywhere so that the controllability of the system -- we stated that where we don't allow transactions to happen. And that's probably the most important element of the simulator.

And with that, I will take some

questions.

MS. SILVERSTEIN: Thank you very much, Mr. Moeller.

Commissioners, do you have questions?

MR. WOOD: I do. I have a couple clarifications. The state estimator at MISO is fully operational, right?

MR. MOELLER: That's correct. It has been since January.

MR. WOOD: And how is it working?

MR. MOELLER: Very well. You know, there is -- all state estimators -- state estimator models are like raising a child. They're born, but they take a lot of care and feeding. And it's a very gradual -- you're always finding something that needs a little bit of direction. And our transmission owners have been very active in helping us make sure that we have that model in as pristine a form as possible. And it's been very reliable. Strikingly reliable.

MR. WOOD: Now, that would include points also from outside of your system, right?

MR. MOELLER: Yeah. The way our model works, we have no direct data from an individual substation. All of our data comes from our transmission owners. So they collect the data on a 2- or 4-second interval and they hand it to us. We take it from each individual control area on about a 10-second interval, but it takes us 30 seconds, about, to get all of the data from all of our transmission owners.

We also bring in data from Southwestern Power Pool, and they have kind of the same regime. So we take their data and we do the same with PJM, we do the same with TVA. So we have access to a lot of data, and that helps.

MR. WOOD: Would that be the core visualization tool, or are there other data that are reliably coordinated and in the system?

MR. MOELLER: Excuse me. We would characterize that as a reliability tool rather than a visualization tool.

MR. WOOD: Okay.

MR. MOELLER: Because -- and it's -- giving an example, you're turning the headlights on in your car so you can see further down the road. The visualization tool takes that raw data before it goes through that process and it displays that raw data to the operator on a series of one-line displays that are for the present and currently operating.

MR. WOOD: I was glad you mentioned the seams agreement issues with PJM, and you mentioned in passing also SPP and TVA. We do need to get that one done. That was one of the lists that we needed to get done for the RTOs.

MR. MOELLER: Oddly enough, my boss told me that same thing last week.

MR. WOOD: Right, right. You know, I was commenting on -- I think hearing the first three talking got me -- I don't want to use the word concerned, but it scratches my head if the answer to all this stuff from a lot of last summer is, let's just take a lot of transmission capacity off the books and not use it just to be cautious. I don't know if we've learned anything. We hear you talk about the reliability tools, visualization tools to actually use the current system more smartly, that's great, but you know, it kind of goes to the point of, gosh, that's not good at all. I think that's the point where we have a lot more wires. And, I don't know, it sounds like the 21st century ought to be a little more reliable than that.

MR. MOELLER: Let me try to elaborate a little bit. The tool that the LMP market will bring is a very important tool to give us that controllability. In the meantime, what we're attempting to do would be conservative in not overbooking the system. So it's -- the way the system was operated was the same way the airlines have from time to time when they've got, you know, 180 seats and they sell 220 tickets. And when you're in that bad of an overbooking situation, somebody gets bumped. What we're trying to do is not overbook the plane to the degree that we have before.

MR. WOOD: One final question. Do you think that the -- this came out of, I think, the blackout report. Do you think that the relationship between MISO and the different control areas is clear as to who does what so that there's not a it-was-his-job kind of excuse thing going on if this ever happens again, or to prevent it from happening again, that the duties and the split of responsibilities between MISO and the RTO and the reliability coordinator and the different TOs who have a lot of control area responsibility historically, is that division very clearly laid out and enunciated so that everybody knows as of today that if this happens, it's my job, if this happens, it's Clair's job, if this happens, it's PJM's job?

MR. MOELLER: In a word, yes. Obviously, that's a much more granular relationship than that. The thing that is most different now than it was year ago is the early collaboration between operators and the Midwest ISO and with our transmission owners, so that at the first hint of risk, conversations are going on to make sure there's an appropriate action plan.

Since that time frame, there has never been an event where a Midwest ISO operator directed action of one of its transmission owners and the transmission owner did not execute that action. Where prior to August 13th, there was some confusion around whether or not MISO indeed did have the authority to direct

action. And that, we have cleared up.
MR. WOOD: Thank you.
MS. SILVERSTEIN: Any other commissioners have questions?
Commissioner Brownell.
MS. BROWNELL: Thank you. I want to clear up a couple of questions. Would the reliability of the Midwest be better served with the consolidation of control areas?
MR. MOELLER: The important part of the consolidation is the control itself. The ability to move generators in response to events is the important thing for reliability. The control areas at this point in time are the ones that have that direct control. Control would increase if control areas were consolidated, but not without significant technology also being employed, so that the control systems, computer systems could replace that job that is currently being done by 35 or 40 other role schemes. So it's a very complicated event to use those control areas.
MS. BROWNELL: But it's been done in other regions?
MR. MOELLER: It has been done in

other regions. The difference in the Midwest ISO would be a question of scope. The 130,000 megawatts from the Arctic Circle to Kentucky brings considerable challenges. The result of that kind of study probably will be two or three or perhaps four control areas that would be involved.

MS. BROWNELL: It's been suggested by some that the events of August 14th and the challenges that have been faced, the TLRs, have, in fact, been caused by competitive markets. What I thought I heard you say was that competitive markets bring better and more efficient solutions by sending the right economic signals. Can you speak to that?

MR. MOELLER: Sure. The advantage that we see in an LMP-type market is it rewards appropriate behavior from a reliability standpoint, because the economics of dispatch and the need from a reliability standpoint are coincident. Where today, in a traditional market, past time market, there is not that influence of signal.

So the avoiding the risk part of the equation is enhanced by the ability to send price signals to give the participants in the market a signal that says, "If you do this, we're all better off." And we've seen that work at PJM, we've seen that work at other markets. We're quite confident that that will, in fact, increase the ability to use the system, because you don't have those conflicting rules.

MS. BROWNELL: Thank you.

MS. SILVERSTEIN: Any other commissioners?

Thank you very much.

Our next presenter will be Kerry Stroup, Manager of Regulatory Policy for PJM.

MR. STROUP: Thank you very much. Chairman Wood, commissioners, it is my pleasure to be here today. You have perhaps anticipated seeing Karl Pfirrmann, the president of PJM Western Region sitting here, but we had a lesson ourselves in reliability last evening as I received a phone call at about 9:30 where Mr. Pfirrmann couldn't get out of Philadelphia because of the cancellation of flights. So I'm here today.

I'm one of the contingency cases today to deliver Mr. Pfirrmann's presentation.

And as you see, it's entitled "PJM's Perspective on Reliability - Summer 2004 and Beyond."

I do want to talk a little bit about the situation with PJM this summer from the perspective of giving you the kind of statute groups for supply and demand kinds of balances and so on, because reliability can be looked at in probably a different number of different perspectives. I will, however, hone in specifically on the things that PJM has done, the lessons learned from the August 14, 2003 outage last year, and then try to finish up with a look in the future, that being the unfolding of the Joint Common Market, which, in fact, is -- there are steps being taken as we speak, and a number of steps being taken to form an operating agreement to put that Joint Common Market into place, which will, as the other presenters on the panel have articulated as well, forming -- enable reliability to be maintained through a market, LMP-market-based system that aligns incentives and need.

Let's begin by talking about the PJM control area and the profile for the summer of 2004. The first thing I wanted to note was that the summer -- this summer transmission system performance is anticipated to meet the MAAC, ECAR and MAIN criteria in the various sections of the PJM control area, that being the Mid-Atlantic region, MAAC, LG&E Power, ECAR, and the contingency criteria will be met to each of those regions, while there were some minor differences in the regional protocols for establishing for this criteria.

The second point here is that as we anticipate this upcoming summer, given normal weather and given what is anticipated with respect to generation performance, we don't anticipate PJM needing assistance from neighboring regions with regard to capacity.

In the event, however, that the weather isn't normal, or that the generation performance doesn't proceed as anticipated, assistance will be available from surrounding reliability regions.

The third point here is that the PJM control area does anticipate a record summer peak this summer. That's not bad news. In fact, it's kind of the way that the history proceeds, I suppose. On the other hand, some good news is that past resources have served that demand, and the PJM control area has increased by 1,465 megawatts since the beginning of last summer.

Capacity resources pursuant to PJM rules are deliverable to loads within the control area. So this forbodes good news in terms of the supply/demand balance in PJM. And, in fact, the reserve margin in the PJM control area is anticipated to be 18.6 percent this summer.

Reservations for bulk power sales out of PJM are below historical averages, and their load response resources are available to meet 2.9 percent of the total demand.

So that's the news -- I should say also, probably, although it wasn't on the slide, that this is an area that there are adequate services in place for the reserve margin of over 31 percent to meet loading in that area.

Let me turn to what I think is really the more focused -- the focal point of what we're here to talk about today. And that is the aftermath of the event of last summer, what steps has PJM, other RTOs and the utilities in this region, and more broadly the Midwest, done to make sure that as much as can be done will be done so that won't happen again.

PJM did learn a number of lessons. And as the other panelists have spoken to, also has certified compliance with NERC recommendations with regard to the needs determined to address the issues that were raised by the outage of August 14th.

But immediately after the outage, PJM initiated an internal assessment process. I'll tell you a little bit about that process. The way that went forward was that dispatchers and chief system operators and others who were on shift at the time of the incident, who were on shift prior to the incident and after the incident were all interviewed extensively. Those interviews were conducted in conjunction with the DOE investigation team that was on site within days after the August 14th event.

Another part of the internal assessment process was conducted in feedback sessions with system operation subcommittees over transmission and generation sites, as well as feedback meetings with the FirstEnergy regs.

And then a very closed review of all the transcripts and voice recordings that were available that basically provided a real-time picture of what transpired just prior to, during and after the event.

So in addition, of course, to PJM's own internal assessment, others looked at this event from their own vantage points. NERC, MAAC Outage Review Team, ECAR Outage Review Team and, of course, the U.S.-Canadian team that was assembled to look at the causes of the outage. And as you're probably quite aware by now, the outcome of all of those views was coordination and communication "need to be improved" in order to rectify the situation seen on August 14th.

So what PJM did first of all was to develop an incident response team with an emphasis on formalizing interregional relationships to provoke the appropriate responses. In other words, facilitating, getting information, assuring the right contact names were in place and available, formalizing the process. In addition, there were multiple levels of communication established within PJM and adjacent neighbors as part of this incident response program effort.

A second point was enhancing the reliability coordinator function of PJM. Previously, the shift supervisor was designated as reliability coordinator; and it was determined after the event that that was -- the shift supervisor was really focused primarily on real-time operations within PJM, so an operations engineer or power dispatcher is now assigned as the reliability coordinator who is not engaged in the real-time operations of PJM and can lend more awareness to the reliability coordinator responsibility.

In addition to that, we have accelerated the incorporation of RC areas into the PJM EMS. Previously, there were three separate EMSs with different user interfaces, and those have all been incorporated into the PJM EMS.

There's been much made of the visualization tools, improvements, and PJM as well has been involved in improving visualization tools. In fact, what has been done here was that while it had been planned, it was moved forward. The installation of dynamic map boards in Valley Forge and in Greensburg control rooms that PJM operates.

The interviews really made clear that that visualization tool in Valley Forge really had provided some information of interest to people in the control room regarding falling voltages in the western portion of the system. And so, as a picture is worth a thousand words, these visualization tools will really enable PJM to increase the visibility of their neighboring systems to anticipate more what's happening so that appropriate actions can be taken to rectify the situation.

And then ongoing process improvements are in place to coordinate communication with MISO and neighboring systems. Again, to enhance communications, systems and visualizations.

Karl had been asked to say a few words about -- comment on the ComEd and AEP integrations. And EPL should be listed up there as well. Basically, AEP and EPL will be integrated on October 1st. But I'll just comment very briefly on the fact that larger RTOs -- and PJM will certainly be larger with the incorporation of AEP and EPL, provide a lot of perspective, provide a wide array of reliability tools.

And again, as the panel came before you to see the addition of an LMP-based system and the reliance on that system to manage restraints on the transmissions are superior to the Transmission Line Loading Relief regimen. And, of course, PJM's energy market is the fundamental tool used to make that system work.

In the longer term, PJM and MISO will be involved in longer planning processes to provide for the transmission system upgrades that respond to reliability constraint situations, as well as economic issues that -- where there is uncleaved injection over a long period of time.

There's been some mention prior to my portion of the presentation today of the fact that we have a Joint Operating Agreement, that is PJM and MISO, which is a model for other JOAs that are being put in place across the eastern region. That JOA had really been under development prior to the August 14th outage, which you may know, but the outage only served to articulate the significance and importance of having an agreement like that in place. Which, in essence, really assures that actions taken in one region will reinforce the reliability or market operations in the adjoining region.

How does it do so? By improving interregional communications by protocols for providing continuous information exchange about conditions in adjoining regions and for timely exchange of detailed data and information.

A number of other points I really won't go into in detail, but I should point out that they do really -- that the Joint Operating Agreement will be enhanced when MISO gets its market up and operating because of the ability to better coordinate TLRs at PJM/MISO interface, and then to re-dispatch generation to alleviate congestion on each other's grids and to better respect limits for native load and network usage.

The JOA really is the first phase of the development of a joint and common market. The JOA really intends to work around the seam issues that we're faced with with really different systems operating in MISO and in PJM. But the first phase which, in effect, has been recorded on very recently to FERC, provides for the coordination with MISO operations for enhanced congestion management.

The second phase, which will begin in May of next year when the MISO markets are up, will coordinate real-time management. And then the third and fourth phases will provide for one-stop shopping between a market portal and provides access to both RTOs.

And finally, we will be in a position in the Midwest where dispatch will be integrated between ISO and PJM in such a way to manage congestion as if they were one system.

So this really is the goal we're shooting for, to improve reliability through the initial step as part of the JOA and the eventual establishment of a Joint Common Market across the Midwest, which is what it said on the slide. I won't repeat it again.

Thank you very much, and I would be pleased to take questions.

MS. SILVERSTEIN: Commissioners?

MR. WOOD: We had a workshop at FERC yesterday at our office there which was focused on software and the leadership on the software that's being done for reliability software and market software integrated, and the leadership that's coming from the RTO ISO council and other large players across the country.

And I just wanted to use this opportunity, since, Kerry, you brought that up in your last slide here, but, this coordinated and integrated data exchange between -- among the larger liability coordinators here and the large amount of market operators here in the eastern region was actually inspiring. I was -- Alison was there the whole day, getting down on some of the events.

But the significance of the integrated software approaches that are going on across the different regions really have advanced the coordinated reliability market operation within the eastern region. I just want to see what happens when you hook up to PJM ISO, New York and New England ISO. Also, TVA is a big player in it as well. I know we're going to TVA, we're going to hear from you next, but the thought struck me as Kerry was speaking.

I do think this really -- having

software all move along the same track rather than having vendors design something that you buy. The customers are driving what kind of systems they want, and that's the title change that we saw yesterday at FERC was that the vendors are being very customer responsive and they're all working together on common platforms to get a system that, really, within the next three to five years, it looks like if we do -- everything else, like going to an ATM machine. They work the same in Canada, they work the same in Europe as they do here. It's even better than cell phones do.

So we have some great mental notes from these other industries, and it's nice to see so much progress that we saw yesterday. And since you mentioned it there, I thought I would bring it up.

Did you all have -- and I asked this question of Clair a moment ago, but did you all have sufficient information from MISO, from New York, from the other regions outside of the PJM to be able to properly analyze the real-time state of your system as it's connected to the neighboring systems?

MR. STROUP: Mr. Chairman, I believe it's the same answer to the question as Clair gave. We receive information almost instantaneously from our neighboring systems and incorporate those into our EMS. So we do have a very broad view over much of the data.

MR. WOOD: How deep, like, say how deep southward would you go south of PJM to get --

MR. STROUP: TVA is incorporated in the EMS, and I really couldn't -- I wish I had the answer with regard to the southern utilities, but my colleagues at PJM told me previously that the state estimator that was recently put in place in PJM is truly one in terms of the amount of regional coverage it provides.

MR. SCHRIBER: Kerry, you and others have frequently alluded to enhanced communications. We've seen a lot of slides that said "enhanced communications." Aside from that data, what is an "enhanced communication"? I mean, is it telephone calls that somebody, you know, is on a hotline with someone else all the time? Give us an example.

MR. STROUP: Well, what it is, it involves not only the exchange of data and information, but actually who we would contact. So what it really entails is formalizing the protocols for that communication.

I alluded a little bit earlier in my presentation to, in the event you're in a preservation kind of event, having protocols in place so that you can -- you know who you're going to speak to, and they're going to receive a call from you in MISO.

One of the recommendations that came out of our internal review, for example, was to provide for more reliable bridge contact. I mean, it seems like a simple thing to do. I'm talking about a PJM bridge, because we found out in the aftermath of the outage that there's a lot of noise on the back of the line, we had a little bit of a problem getting everybody on line because of the capacity of the bridge and so on. So that's really part of what I'm talking about when I'm talking about improving communications.

MS. SILVERSTEIN: Any other questions from the commissioners?

Thank you very much.

Our next speaker is Van Wardlaw, Vice-President of the Electric System Operations for the Tennessee Valley Authority.

MR. WARDLAW: Thank you. Thank you for the opportunity to be here with you today. I begin by expressing my appreciation to the commission, the state and federal leaders, to the industry peers for your commitment to reliability. We at TVA very much applaud these efforts.

I would like to spend a few moments and discuss the efforts of the Tennessee Valley Authority in relation to preparedness and our focus on reliability. There's an old adage that he -- that "Him who desires peace prepares for war." There's one thing that a system operator desires. I can assure you, it is peace. As I like to tell our system operators, we're not looking for any excitement.

So we assess their operation for preparedness. We prepared a recipe for the vital plan which focused on the three Ts: trees, tools and training, realizing they have been identified as root causes in most major outages.

Before I discuss the three Ts, let me take just a moment for those of you who may not be familiar with the TVA power system and to share some statistics. These statistics are reported from Valley Authority transmission operators. In addition, there are a number of coordinators within the footprint, because much of the territory is stretching across 10 states, including 200,000 square miles of geography and 30,000 miles of transmission line.

For discussion purposes today I'll be focusing on the TVA footprint. As you can see, we cover around 80,000 square miles, 17,000 miles of transmission lines. We are a wholesaler where we connect to distribution providers, and we do manage a quarter of a million miles of right-of-way and 8.3 million consumers.

You see our peak demand, we are a dual peaking system, and I am pleased to report that on last Friday, which would have been last week, we set an all-time system peak with use last week of a load time of 30,000 megawatts; and I also am pleased to report that we have had no generation transmission or other reliability issues.

So let's begin with trees, the vegetation management. Trees are the main cause of interruption for most utilities, and are especially challenging for us because we operate our systems in different areas. Add to that a very wet, very early summer and we've been quite challenged.

We are focusing on a 230-kV application system. We have done full assessments on these lines in order to make sure that they are ready for the summer. We plan to remove up to half a million trees this fiscal year. We are very pleased that since our fiscal year began last October, we went almost six months in one period of time without a tree contacting any line at any level.

We have filed our FERC vegetation management report. We have also become very active in the industry's efforts in vegetation management and have included our personnel and involved the committees and working groups that are working in this area.

Let's shift from trees to talk

briefly about tools. Let me talk about the primary tool of the operator, which is the infrastructure that we manage. As you can see, we at TVA have been adding infrastructure. In fact, in fiscal year '03, we have add around 140 miles of transmission line, 3 high voltage substation facilities, 2 major switching stations and added 34 new delivery points for our interfaces for our wholesale customers.

All in all, over the last eight years, we have spent $1.25 billion, and are pushing one of our largest capital endeavors ever. We're also very active in our R&D efforts, working with DOE and others, as well as other technological solutions for the future of the industry.

Shifting from trees and tools to talk a little bit more about tools as it relates to increasing grid visibility, which has been a major theme here today. Our focus, much like the others you have heard here, is good decisions from a sea of data, alarms and indicators. We really approach that in three facets: data displays, data transport and data sharing.

Looking first at data visibility, we're very, very active in the development and use of the Power World Simulator, where we use detailed visual graphics to put a snapshot of the grid in front of our operators, color-coded for ease of use, where with a simple glance at a screen, they can see multiple profiles, current flows of magnitude, their active movement and other dynamics that are important to managing the system.

In addition to that, approximately two years ago we launched a major effort referred to as the Power System Optimization Project, or PSOP, which is a multiyear, multimillion dollar investment to increase visibility and terminal points for generators, transmission grids, interchange points and customer data.

We're also focusing on enhancing the transport network. We operate now 2,600 miles of property, and we continue to expand those capabilities to ascertain accurate information, and to Chairman Wood's comment, make sure that we're the optimum through-put through the facilities that we operate.

The third focus area has been data exchange and information sharing. FERC referenced here today our efforts with PJM and MISO. We're also working to the south of our border with the southern company Entergy. And it's my understanding that with that exchange agreement, they're allowing us to share information with them, and also increase our ability to plan the future of the infrastructure.

And then on the national level we've been very active in many of the activities, such as the BMU effort. We have increased visibility across the eastern interchange where we can better understand the overall health of the grid and increase the situation for operators.

A key focus for all of our visibility efforts has been to involve the operators that use the tool. Within the last few years we have installed one of the largest visual map points in the country. We used our operators, who were very heavily involved, in the development of that tool as well as the design and layout of it, which leads us to the third key, which is training.

And our theme with the training of our workforce has been to engage our employees, making sure that they know what do, and just as importantly, are fully empowered to do it. This effort is conducted at our fully operational redundant backup control center, which we refer to as "The Rock." This art facility, built to military specifications during the Cold War, was basically remodeled and modernized to house our backup control center, our training center. It also houses a lot of our coordination center where we provide services for other control areas.

At the same time we're installing a fully functional control room simulator at this facility. We've taken our best operators, teamed them with individuals with similar simulator credentials, and put this on the ground. The focus will be on day-to-day tasks, as well as emergency training, and therefore, operators can be fully scaled and ready to deal with instances that might involve them.

And then our training program has been a very important element of what we've been doing recently in our NERC control area readiness audit. The control area readiness audit, by the way, was a very valuable experience for us, as some of the other speakers have mentioned. The self-assessments that we get, the self-evaluations that we get, including the audit itself were probably as valuable to us as the audit was.

In closing, let me thank you again for this opportunity to share briefly our efforts to support improved grid reliability. I leave with a direct quote from the NERC audit team that I feel adequately reflects the focus of our company on the stock. And I quote, "TVA comits itself to achieve operational excellence and places a major emphasis on reliability." Thank you again for the opportunity to be here.

MS. SILVERSTEIN: Thank you, Mr. Wardlaw.

Commissioners, any questions or comments?

MR. WOOD: I have a couple. First of all, thank you for being here. We deal a lot with the other folks on the panel, just as a part of our general processes, but I'm glad you're here. You guys, in the reliability reviews during the blackout, task force, were a great help. Real leadership there.

I saw on your map that you didn't have any agreements with the Southwest Power Pool. Is that because they're not directly abutting you, or you just don't have them or is that something that we can urge --

MR. WARDLAW: There has been talk in that area. One of the trouble areas are to provide services for is ACI, who is from Missouri who does SPP, they had them so that is something that at least had some initial discussions, and we will be pursuing that.

MR. WOOD: That's good.

MS. SILVERSTEIN: I see no other commissioners leaping for their microphones.

We will turn now to Dr. Paul Barber, who is with the NERC Steering Committee, to talk about the blackout mitigation recommendations and their publication.

DR. BARBER: Okay. Thank you, Alison. I would like to thank Chairman Wood, Chairman Schriber and the other commissioners for giving me the opportunity to present at this conference.

My presentation this morning will focus on the actions that NERC has taken and is taking to prepare for the summer of 2004. Early on in our investigation we determined that there were a number of issues that warranted near-term industry action. And with that finding, with stakeholder endorsement and the board's approval, Mike Gent sent out a letter to the CEOs of all NERC control areas and reliability coordinators asking them to review certain items. That's the near-term actions that we have there.

That was sent out on the 15th of October, and we gave them 60 days to do the review and give us feedback about what they found. The review was done as to what they found.

We got those actions back in, mostly on time, December 15th, and went through those in great detail, created a summary. You can pick that up on the website, and that was available for other people to look at as well.

This review included a number of reliability practices in broad categories such as voltage and reactive management, reliability communications, system monitoring and control, emergency action plans, training for emergencies and vegetation management. These are all topics that we've heard the earlier speakers converse on, and I just wanted to let you know that the industry has actually been working on this for quite a long while.

As the investigation continued, we noted that there are kind of four strategic issues that NERC needed to address. And let's see, I know how to work this machine here. Here we go. And these are the strategic initiatives. We noted the need for stronger compliance enforcement. And I should point out that these strategic conditions eventually evolved due to fairly significant recommendations in both our report and in the task force report.

The second item there is reliability coordinators and control area reliability readiness audits. These are different from the compliance audits. These are looking for best practices. These are helping to try to share these best practices back and forth. And traditionally, NERC had focused on reliability coordinator audits, not so much on the control area audits, and that's changed. I should point out to you that you're going to hear a lot more on these two topics from David Cook later, so I won't go into a lot of detail on this.

Vegetation management is not exactly a new topic for NERC. In the past, it's been a component of rating and maintaining ratings standards of transmission corridors. And NERC's focus then was to basically maintain clearances, whether they came from vegetation or from manmade objects. But not so anymore. It's obvious that we need to pay particular attention to vegetation in both our standards and in our audits. So we've got several actions going on that account.

The last item up there, it became clear as we reviewed the previous blackout reports and evaluated what we were finding in this investigation that we needed to do a better job with implementation tracking. And that's the fourth addition up there.

We have done some major work on creating systems so that we can incorporate the findings that are coming out of a lot of different sources. The two sources that in particular we were using were the NERC report and the task force report. We don't mind that they are at issue once in a while, we don't mind that there's overlap, but we have them all in there so we keep track of it.

This tracking system is taking pretty good shape. I've used it considerably for you before we were here for this particular presentation, and I know we're getting a lot of help from DOE and FERC and others in putting material in there and updating it.

We're hoping this system will do a better job to help us ensure that these actions are complete and that there's accountability.

Now I'd like to return back to the recommendations in general. The investigation revealed a number of technical initiatives. I'm not planning on going into a lot of detail on those here, but these are issues, initiatives that are required to prevent or mitigate impacts of future cascading blackouts.

Many of these initiatives were expansions and refinements of the reliability practices that were identified in the 10 -- the October 15th letter. Most of these initiatives are going to require a considerable amount of work well beyond the summer, and we were hoping that our implementation and tracking scheme will keep us on track and keep us as focused as we have been on preparing for the summer of 2004.

Some of the items that are in those technical initiatives, however, contained elements that have to be completed before the summer. And so these items have been incorporated into our reliability rules and verification reviews.

Now I'd like to turn to more specific actions for the summer of 2004. The investigation revealed a number of specific corrective actions that were required to resolve the specific deficiencies leading to the August 14, 2003 cascading outages. Most of these details have been described by previous speakers, so I'll save you from looking at five different slides of those details now.

There's been a tremendous effort in the industry to address these actions. NERC's focus regarding this has been to follow up and verify that the things are being done. We have included in these specific corrective actions not only the ones that were NERC recommendation group approved in February, but also the expanded and added elements that came out of the task force report.

Plans were reviewed and approved as required by the recommendations. We formed assistance teams, and they were sent out to the different agencies and were consulted heavily. We did conduct the audits. The audit reports were very detailed and very pointed in many cases. We got the results certified from all the parties necessary by the 30th of June. And in the past two weeks, those results have been verified by teams on site.

All of the corrective actions have been completed with the -- with some well-vetted exceptions; and I went through those exceptions very carefully, and I think those are things that are just going to require more time and are probably not detrimental to reliability for this summer.

The verification reports are being posted as they're completed. I think we just got one posted this morning. Please go to the NERC website for all those details. In my view, I think we're as ready as we can be. Thank you.

MS. SILVERSTEIN: Thank you, Dr. Barber. Commissioners, any questions for Dr. Barber?

Well, we're moving --

DR. BARBER: Take the slides down, please. We aren't going through that.

MS. SILVERSTEIN: Our next speaker will be the Honorable Commissioner Donald Mason of the Ohio Public Utility Commission, on the topic of vegetation management findings.

MR. MASON: You have to have, I think, for a morning presentation, a more colorful version. Thank you.

As indicated earlier, the final blackout report had indicated as one of the points that needed to be addressed was the vegetation management program of the transmission owners. And with that, on April 1st, and now an information request for, I think, Section 311 of the Federal Power Act requested additional information, which was responded to in the middle of June by the transmission owners. It was a very good response rate.

And as a former local official, I was actually pleased to see that some co-ops even filed a report, though, arguably, they might not have had to participate. I think that was a very good signal.

FERC then worked with the National Association of Regulatory Utility Commissioners, and we spoke often, and continue to today. So, Nora and Pat, for reaching out to the state regulators and using NARUC as a partner in this case, as a partner who will actually analyze information and compile information, we thank you.

I think it's worth noting the critical infrastructure subcommittee, and there are several of us on it, but since I was the closest, I was, I think, volunteered to do the report on behalf of the committee.

So we came up with a series of key observations after reviewing the reports that have been filed with us, and that is, number one, there is a wide range of vegetation management practices and procedures. That's not to say that one is better than the other, that some are deficient, it just states very clearly, in and of itself, that there's a wide range of practices and procedures.

What was interesting to note is there is very little uniformity with right-of-way width, vertical line clearance and inspection frequency and the standards used.

There are some explainable reasons why your right-of-way width and inspection frequency are not uniform, as transmission owners do, in fact, conduct their vegetation management around local terrain, climate, vegetation species, as well as local laws and regulations.

An example would be, you would not expect the same right-of-way needs in, perhaps, Nevada as you would in West Virginia or beautiful southeastern Ohio. So that's a good explanation.

However, we do believe that line clearance practices should be similar. That would be the use of, for example, actual tree trimming, retardants, growth retardants and herbicides.

From a grid reliability perspective, the elimination of preventable transmission line outages is the ultimate goal, and the effectiveness of any vegetation management program really should be judged by that rather than saying, "This has 250 feet, this has 125." The bottom line is, "Do they have preventable transmission line outages?"

Many transmission owners reported they faced obstacles in getting local permits to maintain the right-of-way. Again, this is another key observation that we will touch on later. Even with prudent and diligent efforts, sometimes there were obstacles that were extraneous to the transmission owner.

This graph is sort of hard to read, especially if you're on that side of the room, I might add, but what we're trying to indicate here is that, again, based on voltage class within a respective voltage classes, there were a number of different right-of-ways maintained. That's not to say one is better than the other. It should be the template. And nationally speaking, there is a wide range within each class.

We also noted that a lot of companies used air inspection. And again, not to debate the prudency or the value of air inspections, the point is many had different schedules. Twice annually there were 28 reporting; semiannually, 38 reporting; annually, 39 reporting. Again, it is not to say one is better than the other. It's just to say that there is a wide range of air inspection schedules. And those are fixed wing, I might add, as well as helicopters.

So one of the things we did not ask but became apparent through some of the discussions on the reports that are filed, some of them used fixed wing -- and I'm not sure about helicopters, but some of you that used fixed wing also used other technologies such as infrared and other forms of data recording to allow engineers to go back through and subsequently reexamine or reanalyze areas. But that's something that we really weren't probing into in our report, but it might be worth additional studying to find out, again, what the best practice for that might be.

Again, ground inspection, 5 companies reported twice annually; 25 reported semi -- more than -- excuse me, 5 reported more than twice annually; 25 reported semiannual ground inspections; 76 annually, and it goes on. Again, this is not to say one is better than the other, and you have to measure the effectiveness by virtue of what is the reliability of that system.

In the areas of vertical clearance, again, we give voltage class. We ran into -- we had a wide range, fairly evenly disbursed in what kind of vertical line clearances. Again, respective of those areas that you're serving, the type of tree growth that you have in those areas, the actual species of trees, it could determine many times the type of vertical clearances that you do need.

And in trimming cycle -- and there is a large number, I might state, that is not reported here, because this was not a piece of information that was actually asked for. So some companies put it into their report while others may not have. Since it wasn't asked for, it wasn't given. But it's worthy of noting that the trimming cycles did vary for how often companies came around to trim the trees. Again, perhaps in the future, a year from now, additional information can be requested in particular on this kind of a matter.

On best practices for existing right-of-ways, we found the application of wire zone border concepts -- and I was going to add a graph to this and I didn't, but this shows -- has some ideas. Proper consideration of sag and sway need to be included, frequent field inspection based on vegetation conditions.

But it's also important to have comprehensive important public education programs in those areas, because we think ultimately that helps you with local governmental and public park managers if they understand the need and importance of companies to maintain those right-of-ways.

I might say that I spent about two years in the Department of Natural Resources in Ohio. Actually seven, but in those two I was involved in outdoor agencies and I was very pleased with Ohio, in working with our professionals in the Department of Forestry, what a good understanding working relationship they had on helping -- the state parks people and the forestry people had in helping maintain the proper right-of-way. But that's, again, because you had good public education programs in that part of the state.

There are many obstacles to an effective vegetation management program, and some of these are other governmental agencies. Fifteen companies reported that with the U.S. Forest Service, for example, permitting or approval was a problem. And I may say, for an example, in Ohio, I know it was indicated that working through Wayne National Forest presented problems at times. And, of course, within the Wayne National Forest you have a lot of issues regarding split property rights, so that might complicate things further.

U.S. Fish & Wildlife Service, nine respondents said they had problems there. For example, one of those issues was use of herbicides and growth retardants within watersheds, issues with regard to tree trimming, for example, within time periods that endangered species, or species under study, it might be, you know, delicate parts of their annual cycle. So U.S. Fish & Wildlife, at times, had issues.

Again, national parks, the Department

of Transportation, other federal agencies, state and local governments. And I mentioned earlier, working with local park districts sometimes where a person simply would not want transmission lines to be trimmed. And, of course, private landowners. And many of us are even aware of times when local landowners take utilities to court with injunctions, restraining orders to try to prevent tree trimming. So those, again, are the obstacles.

Then we have this other series of tree ordinances, and out West a lot more with the tribal lands, and the issue of media there. A couple respondents felt that the media in their areas did not properly portray the actions that were needed or taking place, and that actually ended up creating other obstacles with landowners and the public.

Recommendations. For example, the United States Congress should enact electric reliability provisions to make reliability standards mandatory and enforceable under federal oversight. I think we've heard so many times over the last 11 months, many were surprised that there was no -- in the age of regulation, even though many of us have been hearing about deregulation for many years, people think that everything is regulated. There are some gaps, and this must be one.

Effective transmission vegetation management requires clear, unambiguous, enforceable standards that adequately describe actions necessary by each responsible party. Current jurisdictional responsibility and authority for transmission vegetation management is unclear, so federal and state regulators must cooperate for better reliability.

Many state regulators believe they do not have authority to direct transmission owners to clear vegetation from their system. And that's a good example of a void, perhaps, that a lot of discussion can ultimately lead to good decision-making as to where responsibility should rest.

I might say as an aside, in talking with utilities on this issue, many of them feel more comfortable with state regulators having the authority. And this is not a state-wide issue, but just because they're going to court, state court, common pleas court trying to get action by the state court, may feel that if it's a state utility commission ordering an action, that carries a lot more weight, perhaps a lot more clarity, because the common pleas court might not know how important the FERC is.

MR. WOOD: Just get them cut.

MR. MASON: Federal and state regulators to allow recovery for the costs of vegetation management expenses. Now, I might add that I did not see in any of the reports I saw where any utility action said, "Well, we would like to do this but the regulators have not allowed us to pass on this cause." But if, in fact, this becomes an issue in the future, then that's something that needs to be discussed.

While permitting and environmental requirements properly protect public health, the procedures for implementing those protections are often inconsistent and time-consuming, and can actually significantly hinder the transmission vegetation management. We concluded that the FERC should work with the Council on Environmental Quality, called CEQ, and land management agencies to streamline and better coordinate those requirements.

There are many finite facilities within CEQ; they have been around 20 years. They actually worked to -- with the federal agencies to try to streamline, reduce overlap and sort of help to decrease the response time of federal agencies to matters. It reduces conflicts, I might say.

Federal, state and local land managers should develop rush procedures to allow utilities to correct dangerous trees that threaten transmission lines. For example, there is a tree that is in a condition where it is rather clear it is not a matter of whether, it is a matter of when the tree will make contact, then there needs to be a process in place where the transmission owners can work more quickly to get those situations taken care of.

The five-year vegetation management cycle should be shortened and the commission and states should look at the cost-effectiveness of more aggressive vegetation management practices. That sort of goes back up to an earlier point made.

Transmission owners should fully exercise their easement rights for vegetation management and better anticipate and manage the permitting process for scheduled vegetation management. And what we mean by this is we realize sometimes there are long lead times, that just means you have to be adequately staffed and start with the process early enough that your permitting can be completed at the time that your vegetation management actually takes place.

But the other thing is there were times I know when there are easement rights out there, but due to lawsuits threatened by landowners, parties are -- and I don't want to use the word reluctant, but perhaps overly cautious on how to approach that right-of-way. And we are recommending the transmission owners exercise their full rights.

All transmission owners should adopt the integrated vegetation management approach to increase grid reliability. That's, again, everything from people to equipment to herbicides and other growth retardants, types of brush that might be planted in right-of-way areas that would ultimately reduce trees growing within those right-of-way areas. Sometimes if you have brush in an area, it's enough to restrict or suppress tree growth in those areas.

Because local and state governments create obstacles for vegetation management, state regulators and the utility industry should work with the National Conference of State Legislators, NARUC and other organizations to help state and local officials better understand and address transmission vegetation management.

And that I left up there because that's what I was left with at the end of the day. I was worn out, so it was time to end. Thank you very much.

MS. SILVERSTEIN: Thank you, Commissioner Mason. The report that Commissioner Mason was presenting is now in draft as a FERC staff report. We will have copies of that outside for folks to pick up if you're interested.

Commissioners?

MR. WOOD: Don, I just want to briefly say thanks to you. When you and Commissioner Hughes from New Jersey and

Commissioner Ripley from Indiana were at FERC a couple weeks ago digesting the vegetation management report, you had a pile this high, and you were going through every one of these reports with our staff. And I just want to say I very much appreciate your leadership by example. I have enjoyed working with you on a number of issues.

This one was, of course, where there were complaints where it hit the road, but it matters everywhere. There are a lot of issues that go into making a vegetation management regime available, and we've got a ways to go and a number of federal aids, utilities or landowners. Kind of a whole mess of people. But thank you for converting into that into English.

And I know from our side of the fence, we look very forward to working privately with you and the other state commissions on this and the other topics as we try to do with so many people over the years. But this one has real world impact, we have to get it right. So thanks for this, but also thanks for the broader collaborative effort that you have taken.

MR. SCHRIBER: I just want to say, you know, we do have a state homeland security office, I suppose you can say, or committee, and having -- I was supposed to be on it, but I knew that Don was much more capable, interested than I would have been in pursuing that. I know it's a very difficult infrastructure. The committee is sort of a subset or spin-off of that. I want to thank you. You've done a great job. You've filled in for me beautifully. You've done more than anyone could have asked for on the security issues, and I appreciate it.

I do have a question. Do you think -- as you well know, we have a lot of guys, men and women in the field from our commission doing lots of things, inspections of all sorts of things from pipelines to telephone infrastructures. Do you think it's a role for the states, at least for our state, to have people on the ground and actually doing the inspections at these right-of-ways?

MR. MASON: You know, if you take a look at one of our earlier observations, we mentioned that truly the best way of judging a vegetation management plan of a transmission owner is, did they have outages that were based on vegetation management issues? So I guess my thought, Mr. Chairman, is if you're working with the company where your complaints coming in indicate reliability issues, and the response by the company tells you that it was transmission and not distribution based or something else, then I would say that that might be prudent for the regulators to actually be engaged at that level.

But if you're with a company where the reliability-related issues don't seem to be related to transmission -- or to transmission and not vegetation, then I don't know that you really have to put more people on the ground, necessarily, in that area.

MR. SCHRIBER: Thanks.

MS. SILVERSTEIN: Any other questions from commissioners? Let me add before we go to audience questions, if there are any, that all of the presentations from today where we have Power Points, they will be posted on the commission's website, www.ferc.gov. Although looking around the room, most of you already know that e-mail address by heart, I'm sure.

Do we have any questions from the audience?

Yes, sir. Please introduce yourself by name and company.

MR. GELFAN: Good morning, Chairman Wood, Chairman Schriber, commissioners, panelists, members of the public. Thank you for this opportunity, and welcome to Cleveland.

My name is Marty Gelfan. I'm here on behalf of Congressman Dennis Kucinich, and I appreciate FERC coming up to Cleveland to control this hearing and this workshop.

I think that since the blackout last year, the regulators have really done a good job of focusing on the problem and bringing the industry together to take a look at what some of the solutions are.

And I want to commend you also on this staff report. I think there are some very good points in here. And on all of -- Commissioner Mason, there was a very good presentation on the vegetation, and that's a concern of the Congressman's. And I also note that you're looking at the past legislation in Congress on this, and that's duly noted and I will certainly pass that on to the Congressman.

One of the issues that arises here in this district is neighbors, people who live on streets adjacent to power lines who have trees that arguably are in the way of the power lines, arguably are not the way of power lines, and I think that some of the recommendations here address that conflict. I think that on page 7 of your report, under "Staff findings," the, "Staff recommends that the commission seek to convene the industry, states and other stakeholders to address the remaining issues." And I think "other stakeholders" included your neighbors. The industry's neighbors. The transmission line owner's neighbors, because they are affected by this.

For all of those cases in the common pleas court that Commissioner Mason talked about -- I think there were 19 -- each one of those cases represents a failure not in keeping the power lines clear, but a failure in the utility owner or the transmission line owner to communicate with its neighbors on what the needs are, and to clearly articulate that there is a need to take down the trees, or at least sit down and negotiate maybe a different way that can be done to deal with potential conflicts in the future. Because in many of the cases, the trees are not interfering with the power lines, it's just that if the utility feels that it has the right to take down the tree, it will.

And that's certainly the case here in the Cleveland this year with FirstEnergy. They have been very aggressive in taking down trees when it may not even be necessary to do so. And I think that needs to be much more focused on the conflict between neighbors and the potential for conflict with utility line.

And I also note that in the staff recommendations, that, "No reporting utility suggests that a lack of financial resources or recovery of vegetation management expenses is an obstacle to the achievement of vegetation management goals." And I think that just cutting down trees because you can is not the answer.

You have the money to adequately manage your vegetation. That's what you should be doing. You shouldn't be cutting expenses by just cutting everything down. Work with your neighbors. That should be included in the future reports of the FERC and the PUCO and NARUC. Work with the neighbors. Avoid conflicts by working with your neighbors and coming to a resolution before it becomes a court case. And I think that would go a long way in making this a great report.

MS. SILVERSTEIN: Thank you very much.

Our next question, please?

MR. MASON: I would like to clarify two things. I think we're not quite accurate on that. A tree does not actually have to come into contact in order to cause problems. You can have arcing that takes effect without actual contact.

Secondly, with sag and sway, there is no way of knowing just by looking, on a day like today, whether the tree must be a problem. That's why you have vegetation management experts who actually try to take a look on a proactive basis as to where a problem might occur.

MR. GELFAN: Once it gets into the common pleas court, it's the utility's expert versus the neighbor's expert, and that's why -- that's the conflict that I'm talking about.

The tree itself, just because it's near a utility line, does not mean that it's going to, in the future, be a problem. It means that it needs to be maintained. And in many cases, pruning can do the job versus cutting.

MS. SILVERSTEIN: Thank you very much for your comments, sir.

MR. GELFAN: You're welcome.

MS. SILVERSTEIN: Next comment, please?

MR. DWORZAK: Good morning. I'm David Dworzak, Edison Electric Institute. And on behalf of EEI, I'm very happy to be here today before you.

Mr. Chairman and commissioners, I've got a couple of questions in terms of what the industry and what my members can expect as we move forward just to determine the preparing and anticipating of what might be happening over the next several months. Two basic questions.

The draft staff report that we just received this morning, is that likely to be the platform or the work-in-progress that will eventually be in Section 311 to Congress?

MR. WOOD: Yes. It's our thought that what you're seeing will be the report to Congress.

MR. DWORZAK: Mr. Chairman, do you have an expectation of when that might happen?

MR. WOOD: In the next several days. We had, actually, some apprehension about presenting it publicly today before we actually deliver it to the people we're supposed to be reporting to.

MR. DWORZAK: Thanks very much.

On standards. As you know, EEI and its members are working hard on the Zero Project. And as of today, we understand that it's continued to be on track, to be concluded at the end of this year, hopefully, where we'll go forward with that. And we've also seen some policy statements, and at various meetings some suggestion that the commission may explore the possibility of referring to or ordering or requesting or proposing that standards, once they are completed and approved by the NERC board, might be incorporated in tariffs as part of the definition of detailed practice. Do you continue to have that expectation? Do you see whether that's where the commission is going?

MR. WOOD: Well, ideally, you know, we like to -- and we've been waiting for Congress to make that kind of fait accompli. If that were to happen, we wouldn't need to worry about what I would consider more second-tier methods of keeping the country's customers more secure.

That effort to codify the existing standards is one that I'm pleased to say Mr. Moore's here from AEP who would agree with the CEO leadership, or EEI, in January, right after the commission's December reliability conference. And that was really one thing that they committed to, that NERC leadership committed to. And I was really pleased -- Mr. Cook was at the board meeting last month -- that NERC is fully committed to February adoption of the NERC Enforceable Standards Version 0 that you referred to in your comments. So that, I would like to see that first.

I think at that point, hopefully,

there will be some legislation by then and then we can move forward and have that be applicable to everybody on the continent, not just the corporations in the USA.

MR. DWORZAK: We are, as you know, fully supportive of that. But just to follow up very briefly, absent legislation, or as an interim measure, a step in anticipation of legislation, do you expect that the commission would make that proposal to incorporate the tariffs?

MR. WOOD: I would -- actually, I would invite the members to put them in their tariffs already so everybody uses their system. And they made the presentation that, perhaps, I think some folks in PJM are interested maybe in moving forward on that. I think while a coast-to-coast approach on that would be welcome, we've got to get started. So volunteers are, I think, always given good seats. So it will be nice to see a few volunteers.

MR. DWORZAK: We appreciate that. Not to hog the microphone, but one final point. We've heard from panelists this morning extensively on issues of coordination and communication, the need for better enhancing, ways and means for both responding to and anticipating various issues with regard to managing the grid. And we've heard from Commissioner Mason this morning on the issue of cooperation between -- the regulatory side between the federal and state.

Can you help us here in the room this morning, just give us a sense of where you see FERC, and in particular, FERC and the states working together going forward to clarify their own authorities and responsibilities to make sure that we're all understanding where we need to go and where my members, especially, need to go with regard to these kinds of liability issues? Where will we see coordination efforts unfolding in the near time?

MR. WOOD: I think, quite frankly, that as it stands right now, the commission's authority on that is rather limited. And until there's a change in that front, we -- and even after there's a change on that front, you know, the states are the front line here. They're the ones who give you the permit to build the transmission line in the first place. They're the ones who you have to deal with with the landowners who aren't, as we just heard, real thrilled sometimes about infrastructure, even though it does keep the lights and the air conditioning on.

So it's just going to have to be a continued cooperation; but I think your front line needs to be with your local commission. And expect us to be sitting there backing them up as we do when the state requests, which allowed all of the regulators in Ohio to know what all the utilities in Pennsylvania, Michigan, Indiana are up to as well. But that's information that's useful to them.

So we'll continue to backstop their efforts and push that on. And again, I think our approach on this specific project is very fine.

MS. BROWNELL: If I could add to that, Pat, some of us just came back from the National Association of State Regulators where we had a meeting about reliability, and I think the states were unanimous in their desire to make sure that we are continuing to work together through the committee on which Don serves and that we are identifying standards that need to in some way be codified.

And I think they were quite clear, that lacking any decision by Congress, we cannot afford to wait to create a system of standards that are clear and crisp and measurable. I think there were great concerns over the independence of the audit process and the integrity of the process. So I think you will consider this a priority of all of the state commissions as well as the FERC; and I certainly know that the industry wants to get to a better place.

It's somewhat embarrassing, I think, in the blackout report to have identified the same six or seven reasons in every blackout that we've had for the last 25 years. That suggests that we better make this a priority.

MR. DWORZAK: We appreciate that, too, Commissioner. I think the question, though, to the extent that the commission requires or proposes references in wholesale tariffs to NERC standards, and to the extent FERC and the state commissions, that we can generally assume have priority responsibility, that there could be some issues going forward.

MS. SILVERSTEIN: Thank you very much.

We have another question, comment on this side of the room.

MR. WHITELEY: Chuck Whitley with Michigan Electric Transmission Company. And there were several references today about data moving very quickly through the reliability coordinators and companies and that, and it painted me a rosy little picture that was presented from my own work with the agency in the past, and current experience here, there's a lot of data that moves between industry participants on, like, 30-second scan rates, and sometimes it takes multiple hops to get from one location to another.

I'm not saying that reliability coordinators need data at the 2- or 10-second-type time frame, but it really isn't there in that type of environment. And I personally would like to see that kind of data available on a control area basis for -- so that we can use that as back-up readings for my own equipment. But on a reliability basis, I can say that sending forth this data, in my experience, just does not move at that type of rate that they're portraying today as being near high-speed availability. That might be something, if someone needs it at that rate, to getting an infrastructure developed to achieve that.

MS. SILVERSTEIN: Thank you very much. Seeing no other commenters, I hearby declare that we are on a 20 minute break. So please be back here at five to 12:00. We will be having a fashionably late lunch. Thank you.

(Thereupon, a recess was taken.)

MS. SILVERSTEIN: Our next topic is Midwest infrastructure, which is critical to electric grid reliability. Our first presenter is Jeff Wright, the chief of the Energy Infrastructure Policy Group within the Federal Energy Regulatory Commission.

Jeff?

MR. WRIGHT: Thank you, Alison. The purpose of my presentation is to give you a quick overview.

MS. SILVERSTEIN: Jeff, move the

microphone closer, please.

MR. WRIGHT: Good noon, I guess is best way to put it.

The purpose of my presentation is a quick overview of the electric and gas infrastructure in the Midwest. And for the purposes of just identifying some systems in this area, the Midwest consists of the colored states on this map, which you see the MAIN and ECAR regions and the TVA.

From 1997 to the present, total Midwest generation capacity increased by just over 20 percent to 206,354 megawatts. Gas-fired capacity more than tripled, accounting for 25 percent of the generating capacity, up from 8 percent in 1997. During the same time period, coal- and nuclear-fired generation capacity declined by 1.3 percent and 8.5 percent respectively.

Coal-fired generation accounts for 55 percent of the total Midwest generation capacity, down from the 67 percent share of capacity in 1997. In 2003, 75 percent of the region's energy output was 670 million megawatt hours from coal-fired, 19 percent from nuclear.

Despite the dramatic increases in natural gas capacity, generation output from natural gas consumption constitutes just 2 percent, suggesting that gas-fired generation still acts more as a heating supply rather than base consumption.

In 2002, coal-fired electric generation in the Midwestern states consumed 285 million short tons of coal, about 80 percent of the total coal delivered. Almost half of the coal came from six Midwestern states. For Illinois and Wisconsin, over 70 percent of the coal destined to be used in electric generation in 2002 was produced in Wyoming. For Ohio, 75 percent of the coal delivered for use in electric generation was used in West Virginia, Ohio and Wyoming.

Looking at planned electric generation, gas-fired plants will account for a mere 8 percent of the new generation expected to be built and to come on line between 2004 and 2006. This map shows how gas-fired plants are located primarily on the interstate natural gas grid.

These new plants, and all the major

plants, will cause gas demand in the Midwest to increase by about half a billion cubic feet per day. We can't expect something less than half BCF per day increase; nevertheless, the increase in demand will require some expansion on the natural gas grid.

Looking at electricity imports, we note that Canada is a net exporter to electricity of the entire U.S. with 5,737 gigawatt hours in 2003; however, the Midwestern region is actually a net exporter to Canada. In 2003, the Midwest had net exports of 3,735 gigawatt hours to Canada, and net exports to Canada from the Midwest have increased by 78 percent since 2001.

This slide shows the electric transmission grid in the Midwest, from 230 kilovolts on up. In 1993, there were 25,873 miles of transmission lines. By 2002, the mileage had increased by about 5.1 percent to 27,200 miles. That growth in main high-voltage transmission lines is attributed primarily to the change in NERC region boundaries.

This chart shows the congestion as measured by TLRs level 2 or higher have decreased in ECAR and TVA; however, TLR levels have increased in MAIN. The decrease in TLR in ECAR from 2002 to 2003 is due primarily to the reconfiguration of the NERC regions. Several of the storage locations, including Allegheny Power, moved from ECAR back to MAAC region.

The factors behind TLRs MAIN are due to a lack of redundant network capability in western Wisconsin, Michigan's upper peninsula, and also interconnections for imports from Illinois and northeastern Ohio to Wisconsin are constrained on a daily basis.

This slide shows the congestion is located in the Midwest again as measured by TLRs at level 2 or higher. During the summer of 2003, each locate, ECAR, MAIN and TVA, caused a level 3 flow or higher TLR. This map consolidates the locates.

The TLRs involved in northern Ohio all occurred after the August 14th blackout. Again, Wisconsin has had difficulty with congestion with moving power from west to east and south to north.

This map shows only the most severe congestion, level 5 TLRs. This congestion is located primarily in Wisconsin and Iowa. This map also shows the projects that may ease these severe constraints, as well as other lesser regional constraints. The projects depicted here appear to be designed to resolve immediate problems in reliability, especially in Wisconsin.

Turning briefly to gas, you see the Midwest gas consumption was virtually flat from 1993 to 2003, and was only expected to increase by about one and a half percent by 2006. The residential sector, which accounts for about 40 percent of the demand, is the largest consuming sector in the Midwest, but it has been flat since 1993 and is not expected to grow by 2006.

The industrial sector, the second largest sector, has actually shown a slight decline in demand since 1993. Since 1993, the largest decrease in natural gas consumption in the Midwest has been to serve electric generation requirements. However, this represents only a small portion of overall natural gas usage. By 2006, it's expected to be only about 5 percent of the total natural gas usage in the Midwest.

The Midwest is a pipeline of all sorts of pipes going into and out of the Midwest region. Nineteen major pipelines traverse the eight Midwestern states. From 1995 to 2003, capacity into and through the Midwest improved 12 percent, from 22.8 million cubic feet per day capacity to 25.6 million cubic feet.

The most significant pipeline development in the year 2000 was the commencement of service of the Alliance Pipeline, tasking 1.3 billion cubic feet per day from Canada. Another significant pipeline development in 2001 was the emergence of the rising Guardian pipelines from Illinois into Wisconsin, with a combined capacity of over a billion cubic feet per day.

The Midwest accounts for 20 percent of U.S. gas consumption, but only makes up or only produces 3 percent of our nation's overall gas production.

In addition, imports containing gas to the Midwest account for over one-third of the Midwest's gas consumption, and the Midwest has 41 percent of the U.S. natural gas storage capacity of about 3.4 trillion cubic feet.

That concludes my brief overview. I would like to hand it over to Jeff Webb.

MS. SILVERSTEIN: Thank you very much.

Jeff Webb is the Director of Planning for the Midwest ISO. He will talk about the Midwest transmission planning issues and prospects.

MR. WEBB: Good afternoon, and thank you, Alison. I do appreciate the opportunity to spend just a few minutes here talking about transmission planning, which I think is very appropriate at this time on the heels of the discussion that we've had this morning about operational readiness, because after all, it's the planning of the system that provides the system operators with a system that they can reasonably manage going forward on a day-to-day basis.

And we plan to do this by looking ahead and anticipating or projecting some very specific, relatively severe conditions that could occur on the grid, and develop the infrastructure to be able to withstand those particular conditions, knowing that if the system can withstand those severe conditions, that they ought to be able to withstand what will really happen, which is in all likelihood not that particular set of conditions, but something of no worse severity. It may involve more elements out in different areas, but there would be variations in what the load level is and so on.

So these kinds of conditions that these planners plan for will be referred to as the planning reliability standards; and there will be some more discussion about those standards this afternoon, where we're headed with those.

But I did want to note that increasingly, especially as we move to regional markets, the line between what is a reliability issue or problem and what is an economic or congestion problem is becoming increasingly blurred.

For instance, a congestion issue, in a sense, can be considered a reliability issue for which there is a re-dispatch solution. And if you continue to resolve congestion issues with reliability, re-dispatching as you go forward, you get yourself into a situation where not only do you have escalating costs associated with that resolution of that immediate reliability issue, but you get yourself into a situation where you have less and less dispatch options to address the solutions.

One thing is clear, though, whether it's reliability or congestion, issues of an immediate kind left unresolved cost customers money.

So who are the entities that are planning on wrestling with these planning issues in the Midwest? Of course, it's the combination on a coordinated basis between Midwest ISO, PJM, TVA, the 24 transmission owners and ITCs that make up the Midwest ISO, and 10, effectively 10 transmission owners in PJM.

Now, the perspectives of these individual players is considerably different lumped together, although we coordinate in providing coordinated plans for the system.

The transmission owners naturally have an obligation to reliably serve load responsibilities. They generally focus on developing least-cost plans to meet reliability needs in meeting that obligation. And, of course, their focus is, for the most part, on their local footprint, where an obligation lies.

In comparison to that, of course, upgrade news here about the RTO's perspective is much broader than that when charged with the ultimate coordinated planning responsibility for much larger regions than the individual transmission owner.

We also have in our planning charge the identification of not only the reliability needs, but also expansions that would address commercially beneficial -- commercial benefits to customers.

So our focus is overall on the integration of the regional needs, the benefits of customers.

When the Midwest ISO applied this regional perspective in our first plan, which we released about this time last year, the plan was very much a two-part plan. One significant part of it was the identification. It was an economic analysis that led us to be able to identify at a first shot level the regional expansion concepts that could ease congestion overall as it compared to what we would expect to see with the reliability plans that had been rolled up, if you will, from the transmission owners.

And also, we looked at reasonable concepts that would not only reduce congestion on the grid, but increase access to generation that may be other than what we saw most predominantly in queue, which was gas-fired generation. We'll talk a little bit more about that in a moment.

On the reliability side, we did see that there was about $1.8 billion of planned transmission expansion, again, primarily to address reliability areas over the period 2002 to 2007. But clearly, most of those plans were to address the local reliability needs, and least-cost plans to address needs, 85 percent of new transmission was at 230 KV and below. Not the kind of transmission that will power long distances, but enough to keep local systems reliable.

So generally what we're saying is that the -- very similar to sub gas at that price -- here we see at the time of the report last year, the most significant constraints that caused curtailments of transactions, and many of them in the Wisconsin and Iowa border.

One thing that, you know, we see in TLR is the balance of transactions. What we don't see is the lack of available transmission capacity to provide for new sales or purchases. So the TLRs don't tell the whole story, and so transmission services, you're curtailing economic transactions, customers are paying a hard price.

So some of the key findings from our plan, again, from the economics side of it, we saw stock market price differentials reflecting the location of coal and some hydro relative to gas-fired generation, and indicating that we have stock market price differentials there in between those interfaces that doesn't allow economic transactions to occur to the extent that they might perform sufficiently.

We saw that the -- what we really did here is we looked at different generation addition scenarios, how did the planned system accommodate the addition of gas meet load versus wind and coal. And so the system can accommodate the addition of gas generation in the locations we would expect that to occur and use with less transmission needs than from some of the other resources as you might expect.

However, the overall economics of meeting a load with gas, given the price volatility, meant that it was bound to pay for that, obviously. And the other coal and wind scenarios, mitigate the gas price effect.

However, in many cases, the new coal and wind resources are in constrained areas or remote locations from the loads, the Illinois coal basin, coal in the upper Midwest; and, of course, the wind, which, kind of interestingly, seems to be where some of the coal is, generally in the upper Midwest, that is.

When we put new coal in, a relatively low cost generation as compared to dispatch of gas, what we found when we dispatched the coal units, the new units -- or the old units, the old efficient coal units, but we couldn't get both out without adding transmission.

So adding transmission would both relieve congestion that existed with known commitments to generation, as well as it would provide access to alternative generation resources would net energy cost benefits to customers. Considerably in excess of the cost of the transmission in many cases. This report is on our website. It's real easily accessible.

Interestingly, also, we found the benefits of transmission, reasonable transmission of significance can extend beyond the Midwest ISO's footprint we're focusing on. I think that suggests that there's a need to consider how to recover costs on a regional basis from the beneficiaries, even outside of the relatively large Midwest ISO footprint.

So, just in summary, the grid generally meets reliability standards. The transmission owners and NERC, I think they've been working effectively overall to meet reliability standards. There's obviously additional work going on in that regard, but meeting reliability is not as was noted, I think at the outset of this meeting, the whole story.

The grid is highly interconnected. We saw that last summer. Reliability impacts have widespread effects, and we can measure, as we did in our report, that the economic impacts also have wide-ranging impacts.

So I think it's important to have an independent regional perspective as we, MISO, bring to this planning process, not only so that we can take our own view of showing you that the reliability -- the plans are being implemented to show the reliability of the system going forward, but also to take this macro view of economic benefits from the standpoint of the customer.

Prospects for needed expansion. I'm confident that the RTO planning, both by Midwest ISO and PJM, and jointly together, will continue to identify the reliability means, and will also continue to identify, as we've begun to do in both RTO, those expansions that will improve the operation of the markets and will reduce congestion.

However, we need a couple of things in the Midwest ISO. We still need a protocol in our transmission tariff to actually include the economically beneficial projects in the regional plans. We have the NERC planning standards, which although they're undergoing some clarification in the modification, that everyone pretty well understands in terms of, "What is the criteria to do a reliability project?" But we don't have a similar criteria for, "When is it the right time to do an economic project?"

And that's what we're trying to develop through some discussions that we've got going on in the Midwest ISO. So we're hoping to conclude by the end of the year; and I know that PJM has made some filings already along those lines.

We also need continuing regulatory help in developing and endorsing these regional expansion and cost recovery policies, because it doesn't do you much good to put it in the regional plan if there is no mechanism to recover the costs of those projects, even if it is demonstrated to be effective and necessary. And also, of course, the siting and facilitating the site of the projects when they come to the ground.

And we have been very happy with the development and the creation of the organization of MISO states at the regional state committee, organized about 32 months ago. They have been very active in many of our committees and functions we have going on with the Midwest ISO. They have a siting committee and pricing committee and they have been -- they have provided us with some guidelines already as to what they think the proper general principles ought to be for cost-recovery issues and pricing along the lines of cost in the region and beneficiary contributing.

So with that, thanks for your attention. I'll take some questions.

MS. SILVERSTEIN: Thank you very much.

Commissioners?

MR. WOOD: Where is -- is all of that then you just focused on in that last issue that you had on there, Jeff, on regulatory help and developing least-cost recovery policies, what -- is that something that's on the deck for the commissioners' group to --

MR. WEBB: Is that something that's on what?

MR. WOOD: On deck for the commissioners to resolve? I know they have a lot going on.

MR. WEBB: Not yet.

MR. WOOD: Do you think that -- are any of those projects -- let me ask you a question. 1.8 billion, you said 85 percent of that was local?

MR. WEBB: Yes. Eighty-five percent of the 1.8 billion is essentially local. 230 KV and below.

MR. WOOD: Generally within a single utility's footprint or not?

MR. WEBB: Yes.

MR. WOOD: So the cost recovery of that is pretty much as it needs to be?

MR. WEBB: That could go that way, yes. And what we're trying to develop, as we talked about earlier, is more of a comprehensive approach where any project -- let's compare an economic-only project that if we developed a measurement criteria that establishes the project is worth going forward with, then we would look to see how do those -- some way of validating those costs along the lines, be that either usage or beneficiaries, the ways we talked about.

You can extend that to say that there

are -- because of my opening comment that there's this range between what's reliability and what's congestion and economic things, if there is economic benefit to what was otherwise construed as a reliability project, just about any project that shows significant economic benefit across a wider area than the zone that it was in might be subject to cross recovery on that basis, not on just that zonal basis. It could continue the way it is today.

But I think what would be more effective would be a more comprehensive approach that looks at any project regardless of the driver, and considers what are its overall benefits in determining that plan. Those are some of the things that we've been discussing with stakeholders.

MR. WOOD: Of the 1.8 billion that were identified last year, is there forward progress made on any of that? Do you have a system to track that? I know it's not yours ultimately, it's proven it's the state commissioners, but is --

MR. WEBB: Yes. Mr. Chairman, I couldn't tell you off the top of my head specific numbers, but we do -- we have a listing of all those projects and we have six-month intervals where we look at the status quos that are going forward. Some of those we have in different categories. Some of them are more firm than others because of the nearness of the need and because of the development of the solution. Others are more tentative or proposed projects, and we review those with transmission owners up against our own reliability studies to see which of those are going forward; and if not, the next question is why not and what have they been replaced with and so on. So yes, we track those.

And right now we're moving forward with our next -- our second expansion plan which we expect to be out probably the first quarter of next year, and that will have a complete update. And there will be changes, because the plan is dynamic. What you think is the right solution five, six years from now, today, a year from now could be replaced. So we recognize that.

MS. SILVERSTEIN: Thank you very much.

Chairman Schriber?

MR. SCHRIBER: Thank you.

Mr. Webber, getting into somewhat what I think is really interesting territory here, primarily because you're reasonably new, you're ramping up to some of these areas, there seems as though there is a normal economic tension between TLRs, LMP pricing, including FTRs, transmission generation. As you go forward, is there a real conscious effort to come to some equilibrium to minimize the cost? Is there an optimum structure here that embodies itself in some methodology or model or something?

MR. WEBB: Yes. I think very much so. What we brought to the table in -- you know, we're not the first and only ones to look at these kinds of things, but what we did in our first plan was in addition to running your -- using your traditional reliability applications to -- we use those tools that mimic these dispatch production costing tools that consider -- you can modify whether they consider whole markets or parts of markets to see what is the actual economic dispatch.

What we're trying to do is anticipate what the LMPs would look like five years forward under the transmission systems. And that's the way -- when you integrate those rules, I think you cover the bases pretty well.

MS. SILVERSTEIN: Commissioners that have questions?

Well, then, it is time for lunch. Please join me in thanking our panelists for the morning. And we will return at 2:00 and start then. Thank you all very much.

(Thereupon, a luncheon recess was taken at 12:29 p.m., with the proceedings to be continued at 2:00 p.m.)

AFTERNOON SESSION

2:09 p.m.

MR. WOOD: I'd like to recognize our wonderful Commissioner Suedeen Kelly, who has now joined us for the afternoon session. And Commissioner Brownell asked us to go ahead and start; she will be here shortly.

MS. SILVERSTEIN: Thank you very much. The morning session was focused on the grid's readiness and the improvements that have been made in preparation for the summer 2004, which has gone pretty well so far.

Our afternoon session will look at longer term liability issues. We have two speakers. The first is Jim Glotfelty, the Director of the Office of Electric Transmission and Distribution for the Department of Energy, and the United States co-chair for the joint U.S.-Canada power system outage investigation team. Jimmy?

MR. GLOTFELTY: Thank you, Alison.

Commissioners, I appreciate the opportunity to be here today to give you an update on where we are on the recommendations of the task force that Alison so eloquently -- I probably don't remember the name of it, but you do. Thank you.

The last time I was in this room, I think it was with Chairman Schriber as well, we were having, last November, our first public meeting on the interim report; and I'm happy to say that I think there are probably twice as many people here today as there were at that first meeting. So I think through all of this, the message is sinking in that reliability is the absolutely number one priority. So I appreciate your support and steadfast persistence in getting the recommendations implemented and resolved within the respective states.

As many of you all know, we extended the life of the task force for a single year after the -- after we released the final report. The sole reason for this was to ensure that these recommendations got implemented. Many times in the past -- in fact, in one whole chapter of the report we talked about recommendations from past blackouts that had not been implemented. We knew these issues, we know the problems. It's just a matter of persevering, kind of being the bad guy, making sure that those who are responsible for implementing the recommendations actually do so. So we extended the task for for a year to ensure that we would have the pulpit to make sure this actually happens.

That means that we have been very involved with FERC, we have been very involved with NERC, we have been very involve with many states to make sure -- and, of course, the industry, to make sure that those recommendations targeted to them are actually making progress.

Many of them have long lead times, long time lines. I'm not expecting them to be completed by this summer, although, of course, many of the ones that NERC -- that were directed towards NERC actually were, and I'll let David talk about those more specifically.

As you all know, the Department of Energy's responsibility in the reliability issue is pretty narrow, but we spent a tremendous amount of time and effort working on real-time grid management tools. It's the technology piece, the visualization piece. We have made an extraordinary effort over the last few months to make sure that everybody who is operating the grid, both in the east and the west, control area level and to the reliability council level, knows the tools we are developing, are working with us to help develop those tools, and to see if they can actually fit into those control tools to increase reliability.

One such effort in the east is the Eastern Interconnect Phaser Project, which gives real-time grid information to control areas. It is modelled after the wide area system in the west, which was put in effect after the '96 blackout in the West. We have a goal of ensuring that there is -- the phaser installations are done in the eastern interconnect by the end of this year.

We have many of them operational today. The system is up and running. This is a backup to each utility's state system data. It's something that we think will be very important going forward, not only as a back-up system, but also as an alternate system to ensure that reliability coordinators actually have data that is reflected on the accurate system conditions.

We have -- in the absence of reliability legislation, which as you know is the most important recommendation from our standpoint, making reliability rules mandatory in this country is the basic building block for a reliable system. It's not the end game, but it's the basic building block, and we continue to work with Congress and push Congress to make sure that they know that. I think they do, but as you know, their energy bill has not passed. We will continue to ask them, work with them, nudge and prod to make sure that they pass the comprehensive energy bill.

In the absence of that, Canada, NERC, DOE, FERC, we have been working, we created what was called a Binational Reliability Oversight Group. The point of this group was to figure out how we make reliability rules as close to mandatory as we can get if we don't have statutory authority, what an ERO, electrical reliability organization, will actually look like, what they will do.

We're trying to make sure that if the legislation passes -- or when it passes, we're not starting with flat feet, that we already have a process, we're already working in Canada. And they don't need to wait for our legislation to pass, they intend for us to move as well.

So it's very important that we not start from flat feet, and I'm happy to report that this group, we work very well together. At some point in time in Mexico, I don't know whether it will actively participate, but we have formalized processes, we have formalized meetings and we are actively trying to make sure that an ERO, whenever it becomes formal, will be ready for work from the very beginning.

I won't talk about -- I'll let Dave talk about the readiness audits. And I will -- Chairman Wood, I will say a few things that FERC is doing. You all obviously know this, and Commissioner Kelly, but for the other commissioners here in the audience, some of the things that were in the blackout report, the recommendations were targeted to FERC, some to the industry, some to the states and some to NERC and some to DOE.

Many of the policy statements that we asked FERC to implement have been implemented in their April 19th policy statement on reliability. That is, new tools, what are good utility practices. There's a whole list. And I'm happy to report that, in fact, we can check those off. They actually have been implemented and they are complete.

I think the other most important point that -- for this summer, not only the reliability readiness audits, but I think it's important to know that many utilities and control areas have actually gone beyond that. They have gone -- those in the western interconnect, as well, have taken the opportunity to look at their training, their visualization tools, and they have implemented things that go far beyond what we had initially said was necessary.

It's important to know that, as you know, from hearing in the meeting the last few days, we continue to have problems. This is not an issue that will be resolved overnight. So the more we can get utilities, control area operators, reliability coordinators, ISOs to take the initiative themselves, to make sure that they know that they're responsible for reliability as the number one issue, I think that makes the day our system will be more reliable for the summer.

I don't have a specific number of the recommendations that have been -- that we say are complete, because the vast majority of them are going to be completed over time. There is not just a definitive end date. But I think those that were most important to address the causes of the blackout on August 14th have been addressed: increased training, obviously, tree trimming. Again, other things that Dave might get into. But I think we are making very good progress. This is not something that will resolve, believe it or not. This needs to be the constant pounding of the drum from August 14th forward.

So we look forward to working with each of you and the industry as we go forward and complete the recommendations and make sure that we continue to be that strong, that we continue to make sure that reliability is going to be strong.

I'll let, I guess, Dave go next, and then if we could get into discussion, that would be great.

MS. SILVERSTEIN: Thank you, very much.

Commissioners, any questions for Mr. Glotfelty?

MR. WOOD: Jimmy, on the developments with Canada, I mean, what kind of steps -- once we get legislation, we'll probably decide to take a different path; but what steps do you think we could take to -- or maybe we could step up the effort a little bit to make that integration better, particularly as we go to other parts of Canada, Ontario, do we do a federal thing, or work with provinces or both? What's the best approach to make that work?

MR. GLOTFELTY: I think it's both. Obviously, the provinces have all of the electricity authority. They have a National Coordinating Council of all the provinces. The leader of that works for the Federal Energy Commission there. And they are working very well together. I would say that on a lot of issues, they're progressive. They want to get it done. They don't want to have to wait for our legislation on many issues.

And then on others, I think we're far ahead of them. We cannot only work with the federal government there, we have to work with the provincial government as well. We're flying blind, I might say. We haven't done this before; but, in fact, we are making great progress. We know where we want to go, we know what has to be done, so we're working together and we will get there.

MR. WOOD: Is there anything we need to do from the FERC side or state side that hasn't been done yet in that regard integrating with Canada?

MR. GLOTFELTY: I think that the only issue is how we continue to work with non-jurisdictional entities. We have worked with our prime marketing administrations to make sure they implement these recommendations as well. As members of NERC's regional council, obviously some of those recommendations are controlled through that effort. But there are -- the tree trimming, the other responsibilities, the training efforts that are absolutely necessary for non-jurisdictionals as well. So it's something that I think we should -- we need to focus on. We need to make sure that they are part of the solutions as well, or they can get lost in the process. You know, for many -- for some municipals or co-ops, there are costs associated with these. We need to be cognizant of that. But in an interconnective system, obviously, they can -- they have to be part of the solution as well.

MR. WOOD: Thank you.

MS. SILVERSTEIN: Do any of the other commissioners have questions for Mr. Glotfelty?

Our next speaker then is Dave Cook, Vice-president and General Counsel for the North American Electric Reliability Counsel. Dave?

MR. COOK: Thank you, Alison, Chairman Wood, Chairman Schriber and commissioners.

I want to talk to you about three things this afternoon. First is a readiness audit program, the status of our work on the reliability standards, and then a place where we need more assistance.

The readiness audit program is, we believe, the single most important thing that we can -- or that NERC can do to enhance the reliability of the system. The goal of the program is to audit all control areas and reliability coordinators on a three-year cycle, with immediate attention given to deficiencies identified in the blackout investigation.

To that end, audits began with FirstEnergy, MISO and PJM. The goal is to identify and share best practices and to highlight areas for improvement. In short, to achieve excellence in reliable operation of all the electric systems. And I should say at this point that a set of slides in the notebook are not the slides I'm using today, in case people are wondering what happened. That's a presentation I gave last week.

In terms of the audit program, we assembled a team of experts for each audit with representation from within the region as well as outside the region. FERC staff has participated in each of the audits done so far.

In advance of the audit we send questionnaires to the control area, its neighbors and its reliability coordinator. The team conducts a site visit and holds an exit interview with the company at the end of the site visit to confirm factual matters and to share the preliminary conclusions.

We provide the control area with a draft of the audit report, and give them an opportunity to comment on the draft. We also provide them an opportunity to give us a statement that will accompany the final report. We conduct these audits on a confidential basis, but the final report is made public by posting it on the NERC website.

We had said we would conduct audits of 20 of the largest control areas by the end of June. That was the task that we set out at the board of trustees meeting in February, and this is the list of audited entities. We completed site visits for all of these by mid-June, and we posted final audit reports on 13 of them. That's the list on the left. We are in the process of completing the audit reports for those on the -- in the right-hand column, and we expect to be posting those audit reports over the next few weeks.

Even though we have just 13 of the reports posted at this point, we can begin to describe some findings of interest. In the best practices area, we've seen excellent training programs, very strong back-up centers, very innovative ways of monitoring reactivates, and good procedures for managing off-site voltage control at nuclear power plants.

Interestingly, the list of areas for improvement looks very much like the list of best practices. It seems clear to me, and this is -- at this point, these are some of my own sort of preliminary conclusions from just perusing the 13 reports we have on the website now.

The industry has the knowledge base and the commitment, you know, on a company-by-company basis on an issue-by-issue basis to deal effectively with these issues. What remains to be done is to sort of raise the bar across the industry and get these best practices translated into all of the reliability coordinators and control areas.

We firmly believe that the readiness audit program can go a long way toward achieving that. Volunteers participating on the audit teams are already beginning to take best practices back to their own organizations and beginning to implement them. Control areas yet to be audited are beginning to assess so that their own standing in regard to the audit questionnaire that we made available to all of them, they're perusing these audit reports as they go up, they can begin to initiate some actions on their own even before we get to their own audits. And we started to get some anecdotal information.

Next steps for the audit program. First, at this point, once we get the rest of these posted, we'll take a bit of a pause to assess the audit program. We've actually begun that already. The team leads and five of the FERC auditors met in Princeton two weeks ago to begin to take stock of the program, to look at the trends that we were seeing in the audit reports, as well as improvements that we can make in the audit program itself.

And we will be summarizing key findings out of these audit reports describing reliability trends and sort of common areas of improvement that we see, as well as the places to focus on best practices and beginning to get the word out on what those are, and then who the companies are that they can go and consult and contact on the areas.

We need to build a sense of community within the electric industry that it's -- there's a book that's been published about nuclear power plants as hostages of each other. And in a sense, we're in the same situation for transmission operators.

August 14th last year made it very clear that all of the operators can be affected by the performance of one of the operators. So a collective sort of raising the bar, a collective push for excellence is really what we all strive to go forward. We intend to look at ways to do that.

In addition, we are in the process of scheduling interviews for the balance of this year. We anticipate 28 more audits this year beginning in August.

I'd like to shift ground now and talk about NERC's development in reliability standards. Completing work on what we call Version 0 is our top priority. We have several, several other important standards under development as well.

What we heard in the task force report, in NERC's policy statement from our own working with standards is that we have clear measurable standards. We have been working under certain multiple sets of reliability rules. We have our operating policies, planning standards. We have a set of compliance. We had a whole new sort of fresh standards effort under way, and things weren't coming together the way they needed to. We need to minimize the impacts of transition and ensure continuity and reliability, and that's why we developed our Version 0 project.

The goal is to restate the existing operating policies and planning standards in terms of the functional model. Policies are a concept of the control area. Replacing it will be standards written in terms of the function being performed and the energy responsible for performing that function.

Functions can then be combined various ways, as we've seen around the country. We will likely have traditional control areas for some period of time, but in other parts of the country, these functions are combined and divided among various entities. We need to set a standard that works across the whole spectrum, regardless of what the market structure is, regardless of how far along people are and what certain people are implementing or restructuring. Our standards are for everybody. The standard will also incorporate the new compliance standards.

Business practices will be separated out from the standards and turned over to the NAESB for further development there. We will add clarity to the standards. For example, an active voice will replace passive voice.

We don't intend to change the substance of the standards in this Version 0. That will enable us to move quickly, because we won't have to have extended debates on what the requirements are. We'll use the existing requirements, and we will do that within the context of our existing ANSI-approved standards process.

Here is where we are right now in the effort. The board approved the accelerated standards transition plan in June. We posted drafts of -- the first draft of the Version 0 standards on July 9th, and those standards are open for a 30-day comment period. We will continue to work on those. There will be further comments in the fall. Standing committees will discuss it, and in November -- we look for a ballot in November or December of this year, then the board will have the full set of versions -- or standards in February 2005.

Other standards that we have on the way. The cyber security standard, which was out last year on an interim basis, it's available. It runs out on August 13th. We've just completed balloting on a one-year extension of that interim standard. I am told it passed; except, under our standard process, if we receive negative comments, we need to do a follow up on a recirculation ballot in order to see if we can build a further consensus by sharing those comments. We'll do that forthwith. We are on track for approval of the extension prior to August 13th.

We had self-certification by the control area reliability coordinators of their compliance of the standards in February of this year. We'll repeat that next year.

We're also drafting the permanent cyber security standard, and that will be in place before the expiration of the interim in August of 2005.

Vegetation management standard is another one that we are working on. Vegetation management, or a lack of vegetation management, was a major factor in the August 14th outage. We need to get some rules in this area, and we're working to do that. We've got a drafting team that's working to make extensive use of the work that the commission has done in accumulating that data. We expect the vegetation management standard to proceed on roughly the same time frame as the Version 0.

There are other standards, needs for standards that have grown out of the investigation. This is a list of the ones that we prioritized. And these are in various stages, but most of them will require some further work before they actually go into standards. So at this juncture, they're in the process of studies being done by teams, by committees under a schedule that will have reports coming back so that when it's clear what the standard needs to be in these areas, we'll be able to move forward with that standard.

We were also in the process of streamlining our standards process, and the votes on that will take place later this summer so that we can move forward on that as well.

Finally, the place where we can use some help. Governor Taft couldn't have said it better this morning about the need for legislation which has been repeated here. We're not standing by waiting for that to happen. We're moving aggressively on these other fronts. But the fact remains that the issues that called for the passage of the reliability legislation haven't really changed. You see it now more than ever.

Right now, everyone's attention is on reliability. That will not always be the case. People will move on, other issues will take priority, memories will fade. We need the legislation to maintain a focus on reliability on an ongoing basis. And policy makers can make a difference in that, and so we really request that you use your good offices to speak to the powers that be in Congress and get this thing done, however it -- whatever it takes to get that done.

Thanks very much.

MS. SILVERSTEIN: Thank you, Mr. Cook. And I would like to say on behalf of the Blackout Investigation Vegetation Management Team that we appreciate you all adopting our local tree-conducting diagram as the industry standard.

Do any of the commissioners have questions or comments for Mr. Cook?

MR. WOOD: I just have one small note. On the additional priority standards, again, those are ones that are not going to be in Version 0, right?

MR. COOK: Those are not in Version 0. The work is sort of going on in a parallel path. Recall, we had that full set of standards, sort of brand new standards that we have been working on, and we have de-emphasized those right now mostly to concentrate on Version 0. But these are issues that we also need to pay attention to now, and they're getting current attention.

MR. WOOD: The third one is something you called organization certification. Is that for the control area reliability coordinator?

MR. COOK: That's right.

MR. WOOD: Is there much discussion about what the standards in the control area would be? Is there a sense that they're not clear now, there aren't any, or that they need to be a little bit stiffer, a lot stiffer?

MR. COOK: I think the issue right now is that across North America, the different organizations have sort of divided up responsibilities differently. And so when we look to a common set of criteria for control, for balancing authority for the reliability authorities, some of it, sort of the organizational issues are falling over into these sort of entity issues, and we're still sorting through those. We've gotten a pretty clear set of criteria for control areas now. It's just translating those into the terms of the function that's the effort.

MS. SILVERSTEIN: Thank you.

Are there any other questions or comments for Mr. Cook?

MS. BROWNELL: Yes. David, you've spoken about many things, but you haven't really spoken about the audit process. What you really did here was review it because if you don't have standards, you don't have anything to audit. But are you planning to reorganize the regions? Are you planning to continue to use peer review as opposed to what I call the Federal Reserve Model where you have professionals who are independent from the banking industry themselves do the review? Is NERC looking at its own organization to equip itself to deal with what will be a new role?

MR. COOK: We have staffing up on our compliance -- on our compliance side to pursue those issues. Compliance enforcement through regional entities is still the model that we're working on, and it's -- what those regional entities will be and how they will be restructured is still a bit of a question.

We have begun the discussions about what the role of the regional council ought to be. These are some issues that were raised in the early part of the task force report, and those -- we've begun those discussions.

Whether it goes all the way to the banking model that you described or not, I'm not sure. There is a great benefit that comes from having the peer expertise brought to bear, and whether, you know, in this industry, you know, at this time, you know, that's a model to pursue. I mean, certainly, discussion can be had, but I certainly would not want to lose the benefit of the industry expertise that we have from the -- some of the asset owners, the people that operate the system participating in that effort.

MS. BROWNELL: You're having discussions -- we've been having discussions about the liability standards for a long time. We're anticipating some legislative action. How long will it be before the organizational issues of NERC and its delivery compliance system are resolved?

MR. COOK: I don't know.

MS. BROWNELL: Or when do you think that will happen?

MR. COOK: I don't have that

answer for you.

MS. BROWNELL: I think that's an important part of the fix, and I would hope that the NERC board would give that some priority. I think that -- I think the report itself made that very clear, so I hope that moves up a line.

MR. COOK: I should say that the legislation has a very -- has a mechanism in it where the commission, in the oversight of the ERO, would have a very active role in working on those issues and looking in anticipation of that. Certainly, it's a part of the device for working on those issues.

MS. BROWNELL: I think we would be happy to do so, but as we've all agreed, we're not waiting for the passage of the legislation and -- but I think having anticipated legislation for three years or something, we ought to get beyond the discussion point to the role and the model that we're going to look at that way, for either the commission or the legislation.

MS. SILVERSTEIN: Thank you.

Any other comments or questions for commissioners?

MS. KELLY: David, how did you choose the next 28 utilities that are going to be audited? What was the criteria?

MR. COOK: I don't have all that in mind. The goal is to work our way through all 150, 160 entities on a three-year cycle. The first 20 or so were very large, the very large organizations. This next batch will include some of the smaller organizations so that we get them into the cycle and begin to learn whether there are any differences with the smaller organizations. So some of them are clearly inked into getting smaller entities.

The other part of it is to spread them around, spread them around across North America so that we're not concentrating in one, sort of in one area. Those two criteria I know about. Beyond that, I don't have -- I certainly could get that information for you.

MS. KELLY: And you talked about the fact that people are beginning to talk to each other subsequent to these audits about various practices that they're engaged in. Do you see that process being facilitated by NERC, or is it being formalized in any way, or is NERC documenting it? In other words, are -- is NERC doing anything in the aftermath of the audits, or is your focus solely on the audits?

MR. COOK: I think that's one of the issues on the list of things to talk about in this evaluation phase that we're just entering now. But it's -- our sort of long-term goal is to be able to make much more effective use of identification of best practices in terms of getting that out to the industry so that it's not just do the audit and then move on.

Another aspect is that one of the criticisms of the industry in the task force report is sort of the failure to follow through on reports from prior investigations and so on. The same sort of tracking mechanisms and devices that we're developing for tracking these sort of report recommendations, we will also use for the audit findings so that we don't lose track of those, either. So that that's another way of making sure that we don't just do the audit and then move on, but, in fact, there's follow up.

MR. GLOTFELTY: Which I might say, if I can, to the other -- NERC and DOE, we are creating a joint, very extensive database on how we track these recommendations. Everything that we do, everything that NERC does is entered into a single common database. So we can go back after the fact and find out who we talked to when, what action was taken.

So we have a real comprehensive and in-depth understanding, and we can really evaluate whether the recommendation was completed, fulfilled or not. That's a recommendation in and of itself, but it's important to know that it's done jointly so that the federal government in Canada and the provinces and the federal government in the U.S. as well as NERC can all have access to that database.

MS. KELLY: And do you see it as a static function that there will be this database that people can access, or do you see it more as a proactive function of either DOE or NERC to try and disseminate the information in a way that is helpful?

MR. COOK: I think very much proactive in the sense of looking at what the most effective ways are of doing that. That's clearly got to be a piece of this, and not just have the audit reports sit on a shelf or have a list of recommendations that we checked the box on. This is an ongoing effort. It's not just a single event.

MS. KELLY: And is there a committee within NERC that is taking particular responsibility, or a committee of the board, for this, or is it staff led? How is it being managed?

MR. COOK: For the tracking and so on? It really falls within our compliance program for the audit piece of it. The work on the data extraction mechanism for the recommendations, it's been a staff effort together with FERC and DOE people. They were up in our office last week working through some of these issues.

MS. KELLY: And what role is the board -- does the board have, or do you anticipate the board having, as you complete the audits?

MR. COOK: The board has laid down, has sort of set the standard in the sense to say that we're going to have this audit program. The board is providing the resources to make sure that it happens. And the board certainly has an oversight responsibility to make sure this happens and goes forward. They're running the show at that level.

MS. BROWNELL: When does the database or the tracking system go live, Jimmy?

MR. GLOTFELTY: It's populated a tremendous amount of data today. I think we are in the process of checking it and make sure it is absolutely accurate.

MR. COOK: Yes. The next step will be to sort of web enable it. Right now we're using an access database. So the next step is to move it to the web, and then develop ways of running public reports against it so that the information won't just be available to us, but it will be available to you folks and to others in the industry who are vitally concerned about where we are in this project.

MS. BROWNELL: Is your --

MR. GLOTFELTY: And let me say that this has been a project that began right after the final report was released. It's not something that we're looking back on saying, "Oh, we need to create a database and populate it. Let me try to go back and remember what we've done."

From day one, and I think even before our final report, NERC was tracking their recommendations from February of last year. So we have agreed upon this so we can be assured and they can be assured the recommendations, both theirs and ours, are being implemented.

MR. SCHRIBER: David, of your reliability rules in terms of the operating policies, planning standards, new standards, what have you, how many of those are forthcoming from your members, i.e., the companies themselves, and how many of them are -- I mean, do you get a lot of input from your companies?

MR. COOK: There's a lot of input from the companies. The companies -- and first, it's true they all derive from the existing set of rules, and those have been developed in a consensus process over the years, and we're continuing to use that process so that, you know, as I say, they're out for comment now.

It was an interesting graphic team that put them together with some staff solicitation. There is -- it's out for comment to the whole industry, customers as well as electric utility participants, regulators. All of that material, all of that information is brought back together into the next rounds.

The committees that will consider these have representation from all segments of the industry, customers and regulators, and then they will be ultimately balloted in a process that has representation from all industry segments, customer segments and the regulators.

MS. SILVERSTEIN: Commissioners, we have one more speaker on this panel if we may.

There were several states affected, many states affected by the blackout, but we have a representative here from the State of New York Public Service Commission, Jim Gallagher, who wants to offer some perspective on New York State since the blackout. Jim?

MR. GALLAGHER: Thank you, Alison and Commissioner Wood, Commissioner Schriber, Commissioner Brownell and Commissioner Kelly.

It's my pleasure to be here, and I'm thankful for the opportunity to participate in this conference. What I would like to do is --

the points I want to make are really in three general areas.

First, what we see is the role of the Public Service Commission in New York with respect to reliability; second, actions that have been taken in New York prior to the outage; and lastly, actions that were taken since our investigation after the outage.

With respect to the role of the Public Service Commission in New York, it's a statutory obligation in our state, per New York State law, that consumers receive safe, adequate and reliable public service. And that has really driven our operation since we were established in the early 1900s.

We have reliability jurisdiction over the regulating facilities. We also have a FERC-approved role in the establishment, monitoring and speed resolution of reliability rules of New York, the New York State Reliability Council.

We were also, with respect to recent events, we were charged by the governor in New York State to lead an investigation of the August 14th blackout, and the related impacts of that blackout as they effected electricity, gas, telecommunications, steam and the water systems. So we conducted a comprehensive review, as well as the impacts of the security and customer information. We have released an initial report. We expect to have a final report out shortly.

I'd like to -- before I talk on some of the key recommendations that came out of that report, I first want to cite some of the recommendations that were taken in New York State prior to the August 14th blackout. And I'll lead off by saying, New York has established mandatory reliability criteria, and we have had them in place since the early 1980s following the 1977 blackout. There were over 100 recommendations that the commission made coming out of that 1977 blackout, and they have been implemented and are part of the requirements of New York State.

We -- I should say also that we continue to advocate for mandatory reliability requirements in the New York system.

Secondly, we have been requiring comprehensive vegetation management plans in the state since the early 1980s. These are for electric transmission right-of-ways. We have a staff that field audits office reviews and actively monitor and oversee the implementation of these plans. And we conduct regular training of our own staff.

Again, we're continuing to work with utilities on these vegetation management plans. In fact, revised plans are being submitted to the commission, and later this month we will be reporting to the New York Commission on any differences between task force work recommendations, as well as the practices that are incorporated within our plan.

The New York utilities, in 1977, implemented automatic load shedding on a fairly wide basis, so 50 percent of New York City load and 25 percent of other transmission operator load is currently automatic load shed. Statewide, we have about 50 percent of the state load under frequency load shed.

We have implemented a New York Wide Area Management System to give us real-time situational awareness. We have a fully integrated outage management system so we can plan and appropriately schedule outages with minimal impact of liability. We have implemented extensive cooperative six-month operator training programs, and these have been in place for some time with information on New York ISO. And we have also implemented -- this system has been in place a number of years, real-time monitoring of critical facilities and neighboring control areas.

Unfortunately, right now, ours is only one bus deep into the neighboring control areas, so we are investigating various posts to try to expand that so we have a better idea of what is happening beyond our neighboring states.

I wanted to now turn to steps we have taken since the blackout. As part of our investigation that I mentioned, we reviewed the operating procedures, communication protocols, emergency plans, training materials and equipment operation, both regulated and unregulated companies, and how they performed as a result of the blackout, specifically looking for areas to define practices or develop new practices.

New York ISO is now working on its

second on-line real-time monitoring critical facilities beyond the neighboring control areas. New York ISO and transmission owners are also working towards upgrading recording equipment to accurately receive time stamps. One of the problems we ran into was trying to come up with appropriate histories of what happened as a result of the blackout.

We are focusing very closely on lessons learned from the system restoration process. We restored the system in New York entirely within 30 hours. Probably the biggest challenge being seen in the system in New York, which for the first time in its history was shut down completely. And we are now developing, with the utilities, we're looking at performance implementing the restoration plans and making sure the plans are up-to-date and cover all contingencies.

We're also focusing pretty closely on lessons learned as a result of the communication between companies and customers, as well as the companies and independent generators.

With respect to customer communication, the utilities generally, they are very good; however, during critical periods, like after the blackout, there was some information lost. We're working with the utilities to expand our capacities to respond to such massive events.

For security purposes, we have recommended electric and telephone utilities in the New York ISO pursue the reinforcement of emergency mobile radio capacity, and also having them require wireless priority service, giving them the highest priority for making calls after a major event. This was one of the problems we encountered.

We're also taking steps to ensure the adequacy and regular maintenance of battery backups. This primary effect of communication, second within New York, a large number of back-up generation systems and battery back-up systems failed. We had directed the companies to explore the various alternatives to the systems they have in place and make sure that the equipment is regularly tested and maintained to make sure that when we need these facilities, they will be available.

We're also conducting studies to

determine what physical changes might be necessary to the power system. And by this I mean we're looking at what possible defensive practices New York might take to prevent another occurrence of what happened on August 14th, where in New York our system was operating as planned normally, and then was suddenly taken down by events outside of our service territory.

So these studies are dependent upon the completion of computer modeling and also dynamic situation, exactly what happened. And plans have now been submitted to the New York Safety Reliability Council, and, hopefully, within several months, will begin to identify what hardware, technical or operational fixes might give us more defensive options in the future.

The last two things I want to mention is also the role that we see demand responding to as energy efficiency plans in our efforts. Immediately after the blackout, it wasn't just the New York utilities and generation owners that did a tremendous job of helping us make it through the outage and events after the outage, but it was the customers in New York who took extreme steps to conserve energy, use energy efficiently, responding to requests from the ISO as well as the governor.

We have a large number of programs that have been in place, many response programs. We have about 1,600 megawatts of capacity that is subscribed in New York, which is about one-third of our operating reserves for the state, and we called on that program to help us as we were bringing load back within the state.

One of the critical aspects of restoring power is the need to balance flow and supply. And thanks to our emergency command response programs, we were able to balance all the supply where we haven't generally been able to do it so effectively in the past. That program was tremendously helpful.

The last point is, and the last thing, is working with the New York ISO and the other market participants in New York to develop a comprehensive planning process initially focusing on reliability planning, and this will identify the role of this ISO commission. The attempt, the initial objective will be to try to deal with upgrading requirements to a competitive process, to a market-based process; however, we will have a regulatory backstop in place that we will propose with the ISO proposal to FERC.

In case the customer does not respond, we will have options whether to demand supply, to respond to these reliability needs. Long term, we will be looking at economic planning; but as you know, that is much more contentious in our competitive market.

So in summary, we experienced a lot as a result of the blackout. A lot of it negatively initially. But at the same time we believe that in New York we have learned a great deal, and we're now in the process of implementing those lessons learned and looking forward to cooperating with FERC in the future and trying to improve our system reliability. Thank you.

MS. SILVERSTEIN: Thank you very much.

We also have a representative from the Michigan Public Service Commission. Thank you for attending. Is there anything you would like to share?

MR. BOKRAM: Not today. Thank you.

MS. SILVERSTEIN: Thank you very much.

Commissioners, any questions for Mr. Gallagher?

MR. WOOD: Jim, thank you for being here. I know you all certainly kept up with the chairman on a week-by-week basis on the responses I got from New York. I appreciate what you all have done -- that's also Ohio and Michigan -- from the blackout and all the contributions you made.

We were just talking with some of the reporters about the Michigan report area solutions this morning, and when it came down to it, they had a lot of good data and information there. So I do think that the collaborative efforts of all of us have made our joint understanding and joint emphasis to solve all this a lot better. Thank you for that.

MR. GALLAGHER: Thank you.

MR. WOOD: I want to just add at the end of this about the panel and what actions we're taking with FERC while we're on the record. I know it might be killing it for what we talked about, but for the benefit of everyone else, I do want to mention this.

The Congress has given us the appropriation of an extra $5 million basically, in effect, get a team pulled together. We have, in fact, done that. And I was just recently named director for the team. The $5 million has been spent in order to attract and hire a professional staff with a particular focus on power engineering steps, but also to perform a number of the studies that we're doing to benefit both current efforts and future efforts.

The first of those studies is an operator training study, which certainly fell out of the joint task force report, as well as a particular interest, I think, of our own from our December 1st hearing of last year. That study and the RFP is on the street, and we're expecting that study will be completed this April of '05 and made available for public review and comment to ensure that we have the best analysis and best recommendations to come out of that before there is a final product release.

But it is an assessment of one of the best practices in similar and other industries about what sort of training regimes are in place that can be used for the control room operators, and the people who we really trust to do the air traffic control job for the power grid. We have continued -- some of things they mentioned -- being involved for the readiness audits. Twenty-eight have been done today. We have one or two of our engineering experts on these teams, too, including a couple that are here with us today.

We look forward to continuing cooperation with the NERC, NERC staff, with DOE, with the Canadians, industry and the states in the months and the years ahead on these issues. And with that, we did have a meeting in the spring with the Canadians that was convened by the DOE in Canada that we were planning to follow for the month of September. I think certainly the thought after today would be that in light of -- if Nora has any questions as well -- would be to not only show up with the readiness reports, David, you're talking about the process by which the audit goes forward, the audit, the audit process which I think we and the Canadians certainly have an interest in, in getting right.

So I'll follow up with you all and the board on that, and also continue working on the scheduling this week with you all, with the Canadians, sort of the same people to come back to the commission in September for our promised six-month update on those issues.

So that is what's going on at the present from us. Alison?

MS. SILVERSTEIN: One more item that I'd like to announce publicly, or remind some of you of, and that is the FERC reliability team will be conducting a study of Lake Erie loop flows. As many of you have heard, we started discussing this some time ago.

The team has initiated a study as a first tack to look at the flow of electrons and the flow of dollars and who actually pays for the transactions flowing intended and unintended across transmission paths around Lake Erie. And it will look not only at the electrons, as I said, but who pays for those transmissions and who benefits and who loses when the power goes where it's not expected to go.

Thanks to NERC for the access to data for the past two years. I wish to assure the participants who send transactions across the grid that these results, as we study them, will be looked at only on the consolidated basis, and none of the results that are released will be able -- will be such that anyone can identify individual transactions that have occurred. All of it will be consolidated.

When we get the initial data study completed, FERC intends to meet with all of the interested stakeholders in the study area and through a reliability council to share the preliminary study results, seek feedback and help design -- help FERC design a continued study that addresses the broader side of the issues.

So the first cut that is being addressed now is a preliminary data analysis that will serve as the foundation for a broader study of possible solutions and options, including those related to tariff solutions, market solutions, conventional transmission reinforcements, new or advanced technology solutions and operational protocols.

So they are expecting to hold the technical conference on this topic in November 2004 with all the states to discuss these issues.

With that said, we now move to the opportunity for audience comment. Is there anyone who would like to comment on any of the things that you have heard testified to so far today? Yes, sir.

MR. WHITELEY: Yes. It's Chuck Whiteley again with the Michigan Transmission Company.

On the other side we have the formulation, the integration of the control area with the functional model, but yet on the commission side you said an awful lot about control areas and how many of them there are, what they're doing, how they're being monitored and whatnot. And once NERC is successful in destroying the idea of the control area, how is this all going to come together and remain in balance?

MR. WOOD: One, I think one illustrative example, we actually asked for ISO to come back and tell us for each of the existing units that we formerly called the control areas, who does what function for balancing the reliability planning operation, et cetera.

I would take your general reminder as good advice. We want to get rid of them, quit calling on something that we really haven't been going from, adjust my vocabulary accordingly. But we are asking the units that are involved in these issues to pierce through the old titles and go to the exact job descriptions and tell us who is doing what so everybody knows who is performing what function, particularly on a day where they're credible for that act.

MS. SILVERSTEIN: I see no one else standing at the microphones. In that case I'll ask the Commissioners if they have any closing comments before we end the session.

MR. SCHRIBER: First of all, I would like to thank all of you, and I'm sure I do this on behalf of the Governor and all of us in Ohio, for coming here. Your diligence and your competence and your pleasability is very very highly valued. You've taken the time to engage us, a state commissioner for many times, and we value that.

On a personal note, sort of the silver cloud, the silver lining to the cloud that passed over us on August 14th was the ability to get to know and work with a couple of people, special people. Jimmy, Alison, it was a privilege, and we know that you're not going to be around for the next blackout. We do know that, so we do wish you very well. Again, thank you all for coming very much.

MS. SILVERSTEIN: Thank you. Thank you all very much for coming. Have a good afternoon and have a reliable summer. Bye-bye.

(Thereupon, the proceedings were concluded at 3:11 o'clock p.m.)

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