BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MISCELLANEOUS ITEMS :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

846TH COMMISSION MEETING

OPEN MEETING

Room 2C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, December 17, 2003

10:10 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

ALSO PRESENT:

DAVID L. HOFFMAN, Court Reporter

P R O C E E D I N G S

(10:10 a.m.)

CHAIRMAN WOOD: Good morning. This meeting of the Federal Energy Regulatory Commission will come to order to consider the matters which have been duly posted in accordance with the Government in the Sunshine Act for this time and place.

Please join us in the Pledge to our Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Since our last formal meeting together, the neighborhood got a little more scenic. I did lose a neighbor and got a new one, instead. At this meeting, we wanted to take the good opportunity to recognize recently-retired colleague, Bill Massey, for all his years of wisdom, prudence, humor and occasional off-color remarks whispered in my ear here, so, Suedeen, you don't have to continue that tradition.

(Laughter.)

CHAIRMAN WOOD: I just wanted to say we have the pleasure of having Bill here today, that I had the opportunity recently to walk through our little hall of memorabilia down the hallway here and observe that not only was he fun and smart, but he served at this Commission for the longest period of time since FERC was formed. That's no mean feat, considering the type of things that have happened since May 24, 1993 in both the gas and the power industries, and know that Bill Massey's fingerprints were not only all over those, but, in fact, inspired a lot of the activities that happened to move our nation's wholesale energy markets from traditional, and, I think relatively inefficient regulatory regimes, to one that is driven by market forces and one that is based on efficiency and technological innovation.

I think, Bill, you've been a great colleague for Nora and me during these challenging times that we've been at the Commission, with the pick up of all the pieces of the Western power markets crisis, with the fall of Enron, the doubling of natural gas prices, the blackout over one-sixth of the continent -- it has not been a real quiet time here at FERC, but I can't imagine a more stable hand to be working with than yours. We'll miss you very much.

We have some little party favors for you, however, so I want to take the opportunity now to welcome you back, and also ask if there are any thoughts or comments, any barbs you want to throw. This is your chance.

(Laughter.)

CHAIRMAN WOOD: Let me give you these things on behalf of all of us. Why don't we all get up here. It is tradition at FERC to present to a Commissioner, the flags that flew in his office.

As I mentioned, Bill was here from May 24th 1993, forward, and this is the American Flag and the FERC flag that are now farmed for your office, which we will all look forward to coming to visit. But these are yours.

(Applause.)

CHAIRMAN WOOD: Finally, it's well earned, but it's no surprise, presented to Bill Massey who is hereby deemed an exemplary public servant, for a distinguished career in which her served the vision, mission, and values of the Federal Energy Regulatory Commission, dated this day in December, 2003.

(Applause.)

MR. MASSEY: I have some remarks here.

(Laughter.)

MR. MASSEY: It's a few of my better speeches. I thought I would begin with a few of those. I'm just kidding. I won't do that.

Pat failed to mention my chairmanship.

(Laughter.)

MR. MASSEY: Thank you, that's better.

(Laughter.)

MR. MASSEY: My chairmanship, boy, that was a great weekend, I'll tell you.

(Laughter.)

MR. MASSEY: That was fabulous. Ten and a half years ago when I was first sworn in by Betsy Molhler, I had some hair.

(Laughter.)

MR. MASSEY: A little bit of hair, not much, but a little more than I do now. But it's been a long time.

I have served with really outstanding public servants, Commissioners, and Staff of this Agency. I have so many great memories.

As Pat said, the whole time I've been here, this Agency has been about this steady movement toward better and better market structures for natural gas and electricity. That's what it's been about, and sometimes it's gone smoothly; often, it's gone in a rocky fashion.

It hasn't been a steady march forward; there have been setbacks, of course, but every day of the ten and a half years, I have absolutely loved being at this Agency. Every moment, I wouldn't trade any of the experience I've had.

I've cast 25,000 votes, and I wouldn't change a one of them, and I have worked with some of the finest people I have ever known in my life, the people in this room and the people listening in on the TV.

What a great gift it has been to me. It's been the most satisfying time in my professional career, and it was just like a gift. You know, a lot of people go through their careers and don't have the experience of actually working with a group of people that are very sharply focused on the public interest. It's in the air here; it permeates the building.

It's what this Agency does. It is an exquisite Agency that does the Lord's work, day-in and day-out.

I thank you for giving me the opportunity to work with you these ten years. I thank Betsy, all the other Commissioners that I've served with. Pat and Nora, you know, I'm a yellow dog Democrat, always have been.

(Laughter.)

MR. MASSEY: But I have loved working with these two Republicans over the past two years. We agreed on just about everything, and they have been about as focused on the public interest and making it work for consumers as any people in this City. And I have huge respect for Joe and Suedeen. I didn't get to vote with them, but I think this Agency is in very good hands.

So, I come here today to bid you adieu, but, you know, I'll be around.

(Laughter.)

MR. MASSEY: Susan Court, after my year's cooling off period, I will be around.

(Laughter.)

MR. MASSEY: I won't be around until then. The other thing I'd like to do today is to honor my right arm over the past ten years, my fine staff. I think everyone who has served with me is here this morning, and I want to recognize them: Donna Glasgow -- if they would come up here with me -- Donna Glasgow.

(Applause.)

MR. MASSEY: Linda Lynch. Where is Linda?

(Applause.)

MR. MASSEY: Phil Peters.

(Applause.)

MR. MASSEY: Andrea Hilliard.

(Applause.)

MR. MASSEY: Bud Early.

(Applause.)

MR. MASSEY: Valerie Mercier. Is Valerie here this morning?

(No response.)

MR. MASSEY: I'm sorry she's not.

Gloria Barfield, is Gloria here?

(No response.)

MR. MASSEY: Mary Doyle? Mary is always here.

(Applause.)

MR. MASSEY: Regina Speed-Bost?

(Applause.)

MR. MASSEY: And Mike Bardee.

(Applause.)

MR. MASSEY: I am so proud of my team. They have been exceptional in every way. I have trusted them with everything I have done, and they have never failed me. Thank you so much for your service with me, and thank you all.

(Applause.)

CHAIRMAN WOOD: That's how we start meetings.

(Laughter.)

COMMISSIONER BROWNELL: It will be hard to top that one.

CHAIRMAN WOOD: That good Southern Baptist is going to be missed up here among us Irish Catholic kids. I want to say, though, that it is a pleasure to welcome Joe and Suedeen here. It's an exciting moment for me. I've gotten to know you two so well in the past two-plus years.

I don't know how many times we've vacuumed and shampooed those carpets. You've got the cleanest offices in the entire City of Washington.

(Laughter.)

CHAIRMAN WOOD: It's been just for these last three weeks. I know we were meeting together with hydro licensing last week. At our first formal open meeting, I just want to say how much it means to me, and I know Nora shares this, to have people of your character and integrity and intellectual rigor here at the Commission.

I think we've got some firm and, in some cases, some hard decisions ahead, but I think -- I just want to thank you, and the people of America ought to, too, that folks of your calibre are up here. We'll do the Lord's work in so many different ways. Welcome to the Commission, and we look forward to the many fun days ahead.

COMMISSIONER KELLY: Thank you, Pat. I'd like to take this opportunity to tell Bill, publicly, that I have been honored to have known you for many years. I'm sad that I'm not serving here with you, but I am thankful that you have left some of your staff here.

I wanted to introduce my new staff to all of you:

Donna Glasgow is on my staff, so that's one very good thing coming from Bill's leaving; Maria Vouras, Rahim Amerkhail, and Michael Krauthamer. I'd like to say that this staff in the last few weeks, has put in many months of work.

(Laughter.)

COMMISSIONER KELLY: They have helped me prepare for this meeting, and I'm very grateful to them. Thank you.

COMMISSIONER KELLIHER: I also want to commend Bill's service. I feel like it took me ten and a half years to get here.

(Laughter.)

COMMISSIONER KELLIHER: But you are a true public servant. I have always admired your dedication.

I would also like to introduce my staff. I have not worked here at FERC before, so I hired three grizzled FERC veterans, Kathy Tripodi from DAE, and if you want to stand up, Kathy, so people know you, Kathy came over with me from DOE. We have three FERC grizzled veterans who are here helping me -- Michael Henry, Len Tao, and Nils Nichols.

They're helping me on everything across the board. I'm very happy to be here. I've been watching these meetings religiously for two years. I sometimes mute the volume and pretend I'm a FERC Commissioner.

(Laughter.)

COMMISSIONER KELLIHER: I had some prepared comments and I always tried to close the door beforehand, so that people can't observe me.

(Laughter.)

COMMISSIONER KELLIHER: But I have been practicing for awhile. Thank you. I'm very happy to be here, and I'll try to keep the smile off my face during the meeting and try to appear appropriately serious.

(Laughter.)

CHAIRMAN WOOD: Smiles are okay. Madam Secretary, it's all yours.

SECRETARY SALAS: Good morning, Mr. Chairman, good morning, Commissioners. Once more, welcome to

Commissioners Kelliher and Kelly.

The following items have been struck from the agenda since the issuance of the Sunshine Notice on December 10, 2003:

E-16, E-21, E-55, E-57, E-58, E-67, E -78, G-2, H-9, and C-8.

The consent agenda for this morning is as follows: Electric Items - E-6, 10, 11, 12, 14, 17, 19, 20, 24, 25, 26, 27, 29, 30, 31, 32, 33, 36, 38, 40, 41, 42, 43, 45, 46, 47, 48, 52, 59, 60, 62, 63, 65, 66, 68, 69, 70, 71, 72, 74, 75, 76, 77, and E-79.

Gas Items: G-5, 6, 7, 8, 9, 10, 11, 12, 15, 16, 17, 19, 21, 23, 24, 25, 27, 28, 29, 31, 34, 36, and 37.

Hydro Items: H-6, 7, 10, 11, and 12.

Certificates: C-2, 3, 5, 6, and 7. The specific votes for some of these items are as follows:

I would first note for the record that Commissioner Kelly is not participating in the following matters: E-12, E-17, E -20, E-24, E-25, E-32, E-40, E-63, E-66, E-76, G-5, G-15, G-17, C-3, and C-7.

We also have Commissioner Brownell dissenting, in part, with a statement on E-38, on E-42.

Commissioners Brownell and Kelliher concurring with a joint statement on E-63; Commissioner Brownell dissenting, in part, with a statement. On E-70, Commissioner Brownell dissenting, in part; and G-37, Chairman Wood concurring with a separate statement; and Commissioner Brownell votes first this morning.

COMMISSIONER BROWNELL: Aye, noting my dissent, in part, on E-38, 63 and 70, and my joint concurrence with Commissioner Kelliher on E-32.

COMMISSIONER KELLIHER: Aye, noting my concurrence on E-42.

COMMISSIONER KELLY: Aye, noting that I'm not participating in E-12, 17, 20, 24, 25, 32, 40, 63, 66, 76, and G-5, 15, and 17, C-3 and C-7.

CHAIRMAN WOOD: And aye, with the concurrence on G-37, as noted.

SECRETARY SALAS: The first matter for discussion this morning is A(2). This is a presentation by our staff as a follow up to the December 1, 2003, reliability technical conference.

CHAIRMAN WOOD: I wanted to actually put this item for just some general discussion since we met last Monday.

We had talked with interested people who came up to the mike about reliability standards and the possibility of legislation and the possibility that we may not get legislation and how the Commission can move forward on certain items there in that regard. I know we've had some good feedback both at that conference and since that time.

I know that, Cindy, we had some ideas about a relatively quick step or two that we could take in that regard. Do you want to kind of flesh that out a bit?

MS. MARLETTE: Staff is currently reevaluating the Commission's authority under existing law to address reliability issues. But one of the things we would recommend that the Commission consider on a fairly quick turn basis would be an order proposing to impose reporting requirements on public utilities and jurisdictional licensees that would require them to report to the Commission at the same time they report to NERC any violations of the NERC standards and also to report to the

Commission when NERC has actually found a violation so that information will be public and on file at the Commission.

CHAIRMAN WOOD: If you all agree we will prepare an order for notational voting to do that. It sounds like a modest but appropriate step forward.

COMMISSIONER BROWNELL: I certainly agree I think it's a modest first step. I think that we need to explore perhaps a couple of other things. I'm sure the industry recognizing that reliability is critical and the credibility of the industry on this issue is critical, I think we ought to do a couple of things. I think we ought to explore the idea of asking the companies to report to us and to the general public the investments that they have made in reliability technology. Certainly the interim blackout report identified a number of missing pieces in terms of information technology particularly.

The second thing I think we ought to think about is somehow getting a benchmark in terms of where we are company by company in terms of reliability -- not certainly with the intent of embarrassing anyone or exposing them to any way to criticism.

But since for the last 20 or so years these have been self-reporting, and we know very clearly there has been a real lack particularly in certain regions of reporting, I don't know that we have an idea where we're starting from and I don't know how we'll have an idea of where we go.

So I fully support this as a start. But I think we need to go further so we kind of get a size and scoping picture of what we're dealing with here.

CHAIRMAN WOOD: A thought in that regard, we did recently as, I think, last week -- the President signed our budget authorization that included an additional $5 million for this fiscal year for the Commission to use in reliability issues and in post blackout issues.

Certainly one of the things would be meeting later this week to come back with the plan to bring back to all of you is the ability to audit actual compliance with the existing standards.

They're voluntary but I think it certainly behooves us and NERC and the industry to make sure that some sort of compliance audit in addition to what NERC does today is handled and now we have the resources to actually do that. I think we can certainly do that step in conjunction with the reporting function back as to actual compliance.

Reporting is great but the double check, the trust but verify from a great American comes to mind when you think about some of these issues with compliance. So I'll be bringing back to you all in the near future a plan for how that audit function and what our role conjoined with that of people outside FERC could be, and quite frankly we've got to use dollars to hire people, to loan people until we can actually hire them on our own payroll.

I think we certainly have a long history of doing that in some of our other programs at the agency of using outside help when we need it to fill a need.

The core issue about the standards themselves is something I do want us -- I do want to actually welcome the input we've gotten -- a little bit -- quite frankly not as much as I had thought, from folks last week, subsequent week, I think I may have received one letter but we may have gotten more. I didn't check this morning but I would like to welcome just in general anybody to file in the docket for this posting which is AD02-7. What was the other one? RM?

The docket from last Monday's meeting? We can ask for comments on that.

The comments would be on the Commission's legal authority despite our years of admitting that we didn't have explicit authority in the statute what parts of our various statutes could we look at, either us individually or perhaps with the Department of Energy or other agencies, to support a further step of making these hit for voluntary standard mandatory or compulsory in some manner.

If people in the outside world have thoughts pro or con on that, if you actually say "you don't have authority? We'd like to have you come out and say that earlier rather than later and let us know before we wander very far down this path."

If we could get some thoughts on that in the next three or four weeks that would be helpful for us in Docket AD02-7 would be the perfect place to make those comments and all the Commissioners and our staffs will get those and we can look at them.

Joe?

COMMISSIONER KELLIHER: I just want to say I support a reporting requirement and I just wanted to express disappointment that Congress didn't pass the energy legislation which would have eliminated the need to ask the question of what is FERC's authority, because as you alluded to, FERC's testified for years before Congress in pretty clear terms that it didn't have this authority.

Since the question has been raised by the Congress and didn't pass the legislation I think it's appropriate to revisit what is FERC's legal authority and how far can we go?

Hopefully the Commission can then be in a position to add if it's determined we do have authority, in the event Congress is unable to pass legislation to act rather than to add.

COMMISSIONER KELLY: Pat, my sense was that the meeting several weeks ago on the blackout that there was consensus that mandatory reliability standards were necessary and as quickly as possible. I appreciate staff initiating this step. I support it and I look forward to hearing from all of the industry about FERC's authority to do more than just have reporting requirements.

CHAIRMAN WOOD: We'll keep this on the hottest of hot burners until we resolve it or Congress resolves it for us. So we'll look for that over the next days and weeks and get that reporting requirement issue dealt with.

We appreciate your work on that and thoughts in that regard, okay? Okay-doke.

SECRETARY SALAS: The next issue for discussion this morning is E-1, the Midwest ISO business plan update, implementation of reliability improvements and market design steps. Today we have a presentation by Mr. James Torgeson, the president and CEO for Midwest ISO accompanied by Mr. James Young, chairman of the board of directors and T. Lamm Edwards, member of the board of directors.

CHAIRMAN WOOD: Welcome back, Mr. Torgerson. Again, I want to also welcome Mr. Young and Mr. Edwards from the board of MISO. I think I was out there two months ago -- no, I was out there last week for the monthly membership and board activities in Carmel. We were very interested and committed to helping resolve some of I guess the development issues starting with the events of August 14.

We pointed out through August that that transformation has not gotten finished yet so we are very interested to visit with you and hear from you to hear about the steps MISO has been taking with its board, with its constituencies out there with the other state interests out there as well as with us at FERC, to address particular reliability issues but also broader organizational issues so we're going to give you the opportunity to update the Commission on those.

And at the end of that we'll engage in some discussion about next steps.

MR. TORGERSON: Thank you, Mr. Chairman.

Commissioners, we have a PowerPoint presentation that I thought I'd just run through but please as normal ask me questions whenever they occur. Put the slides up and we'll just start going forward.

(Slide.)

If we can go to the next slide the topics for discussion we have today --

(Slide)

-- we're going to give a brief introduction of the Midwest ISO and then talk about the business plan we've put together. It's still in draft form. We sent it in to our stakeholders and we've also I think circulated it to the Commission. It's out on our website right now also or will be today.

I want to go a little bit over the lessons learned. This is incorporated into our business plan from the August 14 outage. The improvement in reliability, we're taking on the things we've already done and the things we're doing in the near future. We'll spend a minute talking about the joint operating agreement with PJM and then the outreach for the activities we have for the external parties, then an update for the market itself.

If you go to the next slide --

(Slide)

-- this is just a brief introduction of the Midwest ISO. I think as most are aware we are an independent nonprofit, non stock corporation that monitors the transmission grid. We went operational just a little over two years ago on December 15, 2001. We have 35 control areas, 23 transmission owners. We operate two centers, one in Carmel, Indiana, one in St. Paul, Minnesota.

The map you're looking at assumes that Illinois Power and Ameren will be coming in, at least Ameren, through GridAmerica and Illinois Power will be part of the Midwest ISO. And although it covers areas that you see on the map, it's colored in in the upper Midwest, there are a number of entities that really aren't part of the Midwest ISO, such as the Western Area Power Administration, Basin Electric, Dairyland, Great Rivers, Nebraska Public Power, Omaha Public Power, and in Iowa Mid-American.

So those are not part of the Midwest ISO even though the chart shows in more color.

CHAIRMAN WOOD: MidAmerica is not?

MR. TORGERSON: It is not.

CHAIRMAN WOOD: An investor-owned?

MR. TORGERSON: Yes. They were going to be part of TransLink. That has not happened.

CHAIRMAN WOOD: The TransLink members originally were part of MISO except for Nebraska -- the investor-owned utilities that were part of TransLink are still part of MISO?

MR. TORGERSON: That is correct. Excel and Reliant are part of the Midwest ISO. MidAmerica is the only other investor owned, to give you just the scope, including Ameren and Illinois Power we would have 110,000 megawatts of generation, 96,500 miles of transmission lines over an area of over 900,000 square miles.

The next slide --

(Slide)

-- on the business plan is, I broke it down into three areas of focus. This is the thing we've talked to our employees about. These are the areas that we really focus on the business plan.

First is reliability. Reliability is the top priority of the Midwest ISO. We need to get to the point where we have the same observability and visibility as a control area does today and that's what we're working towards by implementing the tools, adding the staff, and increasing the training to make us the premier RTO. That is where we're heading.

Customer service is the second area. In customer service we're training all of our employees to make sure that they understand that customers have choices, that our customers are more than just transmission owners or the market participants. They're the state commissions and really all the stakeholders so we put in a program to really start training all our employees to understand who our customers are and how to react to them. We're moving from a call center mentality to one where we have a proactive customer service organization.

We're also creating an outreach program to work with all of them.

Thirdly, the market implementation -- part of the market implementation is making sure that we communicate the benefit of the market, the ones that I see are very important -- and this really enhances reliability through the security constraint, the commitment, the security constrained economic dispatch. Those are really key components of reliability that the market will bring.

We believe that is critically important. We also believe we have to have a flawless schedule implementation.

This has been pushed back too many times. We have to carry this out perfectly this time. We also have a thorough trials testing program that's being implemented along the way. Most of the software changes if not all of them would be done in the early part of the program and the balance the last six months to be dedicated to training and implementation for the market participants.

Next slide.

(Slide.)

The lessons learned from the August 14th event -- we realize that the bar has been raised with a new forward focus on reliability. The things we've done in the past are not sufficient today so August 14th clearly pointed out.

One thing we clearly have to do is restore the public confidence. That is critical for us because we think we lost it during the August 14th events so that has to be regained.

We're applying the lessons we learned from this unfortunate situation and we're moving forward. We're adding tools and we're aggressively implementing robust reliability tools on a very accelerated schedule.

(Slide.)

On the next slide we have what we've done since August 14th. We have reviewed operations with the control areas, not all of them, but a limited number of them. The state estimator that is on schedule to be fully operational as the primary tool for our reliability coordinators as of January 1st. We've added 15,000 data points since August 14th. We now have 81,000 data points and 30,000 busses in the network model. That's what feeds the state estimator since we put our last software modification in on December 1st we've actually been running at a 98 percent solution availability for the state estimator.

We've also added and begun monitoring an additional 200 flow gate months in our flow gate monitoring tool. That's a 50 percent increase since August 14th. We've added voltage stability studies, we're doing daily studies now in the MISO reliability area and continuously monitoring those against the voltage stability limits that we have for each area.

In our alarming software, we've added the real-time bus voltages and megawatt flows against the limits for everything that's 100 KV and above. That has already been accomplished.

Our control room enhancements -- and we're arranging to meet with others who run control rooms, Florida Power and Light in particular -- where we can go visit them and gain best practice and make sure that what we're doing is tops in the industry.

Our real-time overview displays in the control room have greatly enhanced the ability of the operators to see what's going on, see the big picture immediately. We have also increased staffing and bolstered the training of the control room personnel.

(Slide.)

MR. TORGERSON: The next slide gives us an overview of what the upcoming activities are. We're adding more staff in both Carmel and St. Paul. We're adding shift supervisors in St. Paul on every shift. We're in the process. We haven't hired yet, but we're in the process of hiring a new Executive Director for the St. Paul office that will report directly to me.

We're enhancing our voice communications systems.

In the first quarter, we're going to install a new alarm system that will allow direct connection, not only to all the control areas, but all the outside parties, and with the touch of several buttons, we'll be able to program it so we can get any number of parties that we want to pick up in one phone call.

We have a comprehensive operator training program that we're just starting to put into place. We have our simulator which is going to be fully operational in the first quarter. All we have left to do -- we have all the software, we just have to put the scenarios into the simulator, and in the first quarter, we'll be running all of our operators through the simulator training.

Once the state estimator is fully operational, we'll also start on some enhanced functionality. This will be after January 1st, and the other tools we're implementing, which are all outlined in our business plan, will really improve the information and the flow of information to the Reliability Coordinators. That's all going to be added in the second quarter of next year.

We're going to spend about $13 million in capital and operating costs in these reliability improvements, starting from probably a month ago, through the second quarter of 2004.

(Slide.)

MR. TORGERSON: The next slide will give you a quick overview of the joint operating with PJM. We have a mutual data and communication exchange that really takes continuous real-time exchange of data, the SCDA data, the EMS data, operation planning data, and the planning models that we will have, we'll be sharing that.

We also have complementary system processes such as the ATC and AFC calculations, reciprocal coordination of flowgates, outage coordination, and then emergency procedures.

Then there is the coordinated system congestion management that's based on the congestion management white paper we put together, and we both will be implementing that; then coordinated system planning. We plan to have a joint RTO planning committee and also an interregional planning stakeholder advisory committee to work on the planning, and then the analysis of the interconnection requests will be done jointly.

The shortcoming right now for the joint operating agreement -- there are a couple of items that have not been included to this point, and we'll be pointing this out to the Commission when we make our filing. One is the PJM classic and the AEP Companies, where the flowgates, we believe, need to be included in the reciprocal flowgate coordination. So far, that has not been agreed to.

CHAIRMAN WOOD: Explain that issue.

MR. TORGERSON: The PJM classic would honor the flowgates, or AEP would honor the flowgates in the Midwest ISO and vice versa, and they would coordinate on the flowgates, on making sure they're honored in the calculations of AFCs.

CHAIRMAN WOOD: The reason that's not resolved is what?

MR. TORGERSON: We haven't reached agreement. Mainly, it's numbers; it's monetary issues.

CHAIRMAN WOOD: Isn't it always?

MR. TORGERSON: Also, the outage coordination has to be applicable to AEP.

The third item is the Michigan-Wisconsin hold-harmless resolution, which we know no one is putting in front of the Commission yet, but I would expect something would happen, at least I hope, soon, because the Michigan-Wisconsin hold-harmless have to get resolved.

CHAIRMAN WOOD: For the benefit of my new colleagues here, could you kind of tell us again, what, in general, what kind of issue it actually is.

MR. TORGERSON: It goes back to the July 31, 2001 or 2002 Order that said that for the former Alliance Companies, to allow them to have their elections and go into either PJM or the Midwest ISO, there have to be certain conditions.

One of the conditions is that the utility -- the

States of Michigan and Wisconsin and the utilities in Michigan and Wisconsin had to be held harmless by the election of former Alliance utilities to go to PJM, how they work that out, whether there's compensation. Those were acknowledged or whatever. They have not been.

We had a settlement conference; we've had discussion and there has been no agreement. The parties are at the point where someone has to put forth a plan or a settlement proposal and get it in front of the Commission so that the Commission can act on it. Right now, there's nothing there.

The idea was that the parties should be held harmless from the elections of those companies to not be in the Midwest ISO and to join PJM. That's really the requirement.

(Slide.)

MR. TORGERSON: On my next slide, talking a little bit about our outreach program, we are going to have a more active approach with the media. Burson Marsteller is working with us to help develop this plan, which is being put together within the first quarter, and then we'll be actively working that, starting immediately.

We have a collaborative effort for the market tariff. All of our stakeholders are providing input to the energy market tariff, which will be filed March 31st.

We're doing training to support the stakeholders.

We're readying this for the market. We have a very aggressive training program. We started it last summer, and then the delays in implementing the market were really pushing some of it back, so it will start in the summer, so that all market participants understand and know how to really work in the marketplace and know what the ramifications are to them.

We're also working with the OMS, the Organization of MISO States. They are on the FTR, financial transmission right allocation and also on resource adequacy and a number of other issues, mainly related to the cost allocation for the construction of new facilities and how that could be worked out among the states.

We're having very active input and continuous input from the Organization of MISO States. We also intend to take a leadership role among the RTOs and ISOs in evaluating the strengths and the weaknesses of training operators and what needs to be done, making certain that the operators are doing everything that they possibly can.

(Slide.)

MR. TORGERSON: In my final slide, we have quick update on the Midwest market. We're shooting not -- more than shooting -- we will hit December 1, 2004 for the market to be starting.

In March of 2004, we're initiating initial trials in the market. We'll have the tariff finally in March of 2004, and then we'll start running parallel operations in August of 2004 with final trials in October. We have some software upgrades or updates, whatever you want to call them, that are going to occur through March, whether it will actually be implemented. So that's why we do the parallel operations.

We're going to want to start parallel operations in the middle of the summer, so we're not going to start the parallel operations in the middle of the summer; we'll start in the August timeframe so that we'll see what kind of participation we get. Then the final trials will begin in the Fall when all of the market participants will be in a position to participate.

That concludes the remarks I have, and kind of a quick update on the business plan, which hopefully you all have. It's in draft form. I already saw a couple of things that I need to change in there, more typos than anything else, but really, we would appreciate comments from not only the Commission, but from all of our stakeholders as well.

COMMISSIONER BROWNELL: Business plans are dynamic documents. We expect them to evolve. I have a couple of comments and a couple of questions: I want to say that my visit last week was enlightening. I think that for the first time, I appreciated the size and scope of the task.

MISO is creating what I believe will be the premiere RTO in the country, and in a relatively short period of time, compared to what we've seen. We're always talking about other models. They had 20 years to do it.

The Midwest is doing it on a large scale and scope with a more diverse set of customers and members in a much shorter period of time, and I think we need to remember that. I think that the leadership shown by the Board has been commendable, and the employees are just extraordinary, having been through what has been, at best, as traumatic experience.

They have risen to the task, and just the number of changes -- you highlighted a few, but there are two pages of very specific measurable changes they have made since August 14. I just want to commend you for that.

MR. TORGERSON: Thank you very much.

COMMISSIONER BROWNELL: I have a couple of comments, Jim. How much did the delay in opening markets and some of these missed deadlines, what are the costs of that? We all agree that we need to focus on reliability, but I just want to get a handle on some of those costs.

MR. TORGERSON: The software costs, which are really the consulting costs, added about $18.6 million.

Then we have another $22 million of costs resulting from the delay from fixed expenses we have, such as interest, depreciation, rent, having employees on staff. I just can't terminate employees and expect to hire them again in six months or three months. We have to keep all the employees there.

And then we do have a number of fixed expenses. Our insurance is another big one. All those are costs associated with the delay in the market, because we're delaying it. Basically, the last one was March of next year, pushing it back eight months, so you're looking at some significant costs. In total, it's like $40 million.

COMMISSIONER BROWNELL: One of the things that I think you have agreed to do in the business plan and that we discussed with all the stakeholders, including the state commissioners who have shown really remarkable leadership as well in the Midwest, is to begin to put a price tag on some of the decisions.

The stakeholder process, while meaningful, sometimes adds a lot of costs, and we want to hold ourselves and others accountable, so when they want the gold plate or the special change in the software, I think we have to be pretty clear about what those costs are.

I know you're doing some auditing of that, and I think that will add some value, and frankly, inform all of us.

MR. TORGERSON: We should have the answer to that on what costs went up as a result of stakeholder requests, hopefully by the end of this week. We will certainly get that to you and to the Commission on that point.

The other key is to make certain that as stakeholders or even people within the Midwest ISO, any participants ask for changes in what we're doing, it refers to analysis to determine how much it costs, what the benefits would be that we would derive from that change, before we jump in and say, yeah, this is something we need to do.

As you say, the cost to change and the cost to modify are very expensive, especially as soon as you get into the software changes. They get horrendous because you have to have the vendors who put the software in, make those changes.

COMMISSIONER BROWNELL: When I was visiting with one of your member companies, they raised an issue that their perception was that there had been a decline in service since migrating to MISO.

I asked you to look into that, and to write all of us a letter, which I believe you have. I don't have it here, but could you kind of describe what you found? Describe the issue and then describe what you found to be the actual facts.

MR. TORGERSON: The issue was, are the AFC or available flowgate capacity values, since the Midwest ISO has taken over, have we gotten more conservative in selling transmission service? What we found was that this was up in the MAPP region, and we still use exactly the same tool that was used before. We still have the same employees, the same software, and it's being run in St. Paul Center, so we haven't changed any of the basics that would look at how the tools operated, what the flowgate capacity would be, and how the values would change.

What we did find was that there has been a significant shift in the power flows. Manitoba has had a draught, so in the past, the would export 1200 to 1500 megawatts in peak periods to the south, to the U.S.

What happens is, the power flows are now reversed. They're importing power into Manitoba. That has also caused a reduction in the AFC values that we have and the ability to sell because of the change in the power flows.

We've also seen a significant increase in TLRs, especially TLR-5s in Iowa because the flows are coming up mainly from the Missouri-Iowa region, even the Southwest Power Pool, where they are now selling up into Canada.

So we've seen a change in the flows; we've seen

TLRs being implemented, at -- I won't say a significant rate, but we've seen loadings on flowgates that we never saw before.

That is the main reason for the changes we saw and the reason that people thought maybe our service was degrading, or at least we were selling less transmission capacity. But it was really a function of the draught in Canada and the fact that we're still using the same tool and the same people are still doing the same analysis.

We don't see that there was any change as a result of MISO taking over, but because of the weather. That was the primary reason.

COMMISSIONER BROWNELL: Presumably those companies or that company that experienced the problem, is actually making some money selling into that market in Manitoba. Do you think that's probably true?

MR. TORGERSON: They may be, yes.

COMMISSIONER BROWNELL: The reason I bring it up is, I think it's important, as we evolve into the markets and there are lots of questions, that we be a little more disciplined about raising issues and doing the fact-checking before we start making statements that reflect upon the service quality.

If there's a service quality problem, we need to deal with it, and your efforts in that regard, I think, are going to be well accepted. So I want everyone to know that if there's a problem, let's deal with it, but let's really be sure about what that problem is.

MR. TORGERSON: The thing I want to make sure of is that if people, if they have a problem, call us and let us know, and we can research it and get back to them quickly. That's the other thing we have to do, is respond very fast.

We put in really a rapid response team that's made up of senior people within the Midwest ISO, so when issues get raised, where they're coming from, the Commission -- and with Patrick and Christopher there, they hear things at our site and they can feed it to them. We'll feed things back to them also.

So we're responding to issues that are raised by whether it's stakeholders, market participants, whoever, and they get resolved as quickly as possible. We don't put the days or weeks between someone's concern and an answer coming out.

COMMISSIONER BROWNELL: I think that's really important for your customers. I appreciate that commitment and it would probably be helpful to all of us, as those issue come up, if you kind of let us know, so we are armed with a better understanding of what some of those challenges are.

MR. TORGERSON: That is our intent, to make certain that the responses go to the Commission, as well as the participant who raised the question to begin with.

COMMISSIONER BROWNELL: Thank you.

COMMISSIONER KELLY: Jim, I understand from reading your presentation that you received a lot of input from the Organization of MISO States.

MR. TORGERSON: Yes, we did.

COMMISSIONER KELLY: Could you explain for me, new FERC Commissioner, how that organization works and the role they played?

MR. TORGERSON: Certainly. It was formed voluntarily by the State Commissioners from each state and the Province of Manitoba where the Midwest ISO has operations or the transmission facilities that Midwest ISO has control over.

So, they all pretty much came together, agreed to form the organization. The issues they deal in are MISO-wide issues such as allocation of the financial transmission rights. They look at resource adequacy on a broad regional basis.

One of the big things they're involved in already is planning, planning the entire transmission system. We're working with them already. I think they have seven committees that are set up, planning being one of the key ones where we work with them on our plans for the system.

They will look at it not just state by state but in the OMS on a regional basis and determine if there is a way to allocate benefits and costs for transmission upgrades, not only ones that are just needed but ones that could be done for economic reasons.

They could expand the generation for example of wind power. That's one issue we're dealing with right now, how do we get transmission to access those who want to add wind power in the upper Midwest and North and South Dakota and Minnesota because there isn't the capacity there. But then who pays for the transmission upgrades?

If you're looking at large upgrades that will have to occur, the OMS will be the entity that's working with us on how the benefits would be allocated and also how the cost could be allocated.

So that's one big area I think the OMS is going to provide great value, and all the Commissioners, they elect their own vice president, president, officers and then theyhave meetings which seem to be about every two weeks, on the phone generally. They just had their annual meeting at our headquarters last week.

I'm very optimistic that the OMS is going to provide great value to the Midwest simply because we have all of the Commissioners working jointly on projects that affect their states but also the entire region and they're looking at it from a regional perspective. They still have their state interests. They always will but they're trying to address things on a regional basis now so I'm very optimistic.

COMMISSIONER KELLY: I'm very pleased to hear that. It sounds like an innovation that sounds like it's working. I think it's a big step for the states to take. I'm hoping that, if it does work, continues to work, that it could serve as a model for other parts of the country. Certainly our issues are much broader than just within the state boundaries and having states coming together and working to plan and on the other issues that are important is really encouraging and I want to encourage you and thank you for MISO being open to that and being a forum where that kind of participation can be meaningful.

I have one other question. You talked about cost benefit analysis. Could you explain to me a little more specifically how it works, how it's formalized within MISO.

Who does the cost benefit analysis and how specifically is it taken into account in making decisions?

MR. TORGERSON: The cost benefit analysis I was talking about related to the planning and the transmission system as one. That's where our planners will look at what the impact of the flows on the system are.

When I say "benefits," who actually benefits from having additional transmission there? Does it mean additional transactions can occur? Does it mean generation can access markets? Does it mean the load has more access to generation and can they use the transmission system with the expansion that's there?

So you look at the cost of putting them in, then who can derive from all these benefits? The benefits are many. The reliability of the system is very much one. Anytime you add transmission it will improve the reliability of the system unless you actually do it wrong but I'm not the engineer.

But as soon as you put in more transmission capacity it should improve the reliability so those are benefits everybody would derive in the region where you have this transmission. So our people are the ones doing the analysis then providing this analysis to the OMS then we can jointly make determinations of how we could come up with methods to allocate the cost and what kind of late structure may be appropriate and will bring back to the Commission for approval of that --

COMMISSIONER KELLY: And whether the cost should be incurred --

MR. TORGERSON: Right. To begin with, we do an economic analysis before we put anything into our plan to determine are there benefits broadly and that is and we call it the "MISO transmission expansion plan" that came out last June. It was approved by the board but we put in there our analysis of what potential benefits are at a broad level and now we've got to get it fine-tuned when we actually go to look at the OMS on this cost benefit study.

COMMISSIONER KELLY: Thank you. I think it's important that the public know that you're not running an operation where there's a blank check. I appreciate your elaboration.

MR. TORGERSON: Thank you.

CHAIRMAN WOOD: Will the OMS be driving toward a standard approach to be used for all projects or would it be kind of project-specific?

MR. TORGERSON: It's going to have to be project specific. We'd like to have an overall framework we can work off of but I think each project may be a little bit different and you may have different states involved. We will, we know that. We're going to break it down by the areas within the Midwest ISO where the states are impacted.

For example, if you have North Dakota, South Dakota, Minnesota, there's no need for Indiana and Ohio to get really involved in that.

But we want to have the same methodology but I think the projects are going to dictate --

CHAIRMAN WOOD: The methodology is really what I'm looking for.

MR. TORGERSON: The methodology has to be the same.

CHAIRMAN WOOD: Is that kind of on track to be proposed as a methodology that would be part of your formal tariff; i.e. we would approve the methodology, similar to what we were talking about with New England a few dockets from now?

MR. TORGERSON: I hadn't thought through whether we wanted it in the tariff but it probably makes sense. We may very well.

CHAIRMAN WOOD: I think we've had some encouragement from people across the footprint that they're more interested in getting some certainty for transmission investment purposes in the methodology that would be used so that they know if the Midwest trans-expansion plan has identified this need. How do you get from that identification to construction and what do you do when one of the utilities that would be the natural designee for that says "no I don't want to do it. I can't access the capital markets or for whatever reason I don't want to do it. Does MISO then hold an auction or designate somebody else? Those kind of processes where you actually can get from the concept phase to the energized facility phase?

A really important infrastructure issue -- in solving infrastructure issues not only in your region but everywhere?

MR. TORGERSON: In that transmission owners agreement that formed the Midwest ISO it does talk about that. If it's for reliability purposes we'll start with that and the transmission owner in the area that it would get constructed. They're the ones that are supposed to build it if they can for the reason you just cited. They can't access the capital markets. There's a financial hardship -- then anyone in the Midwest ISO can step up to any party and say "I'll build it. THey can be the ones to do that.

If we don't have anybody then the Midwest ISO can actually step in, hire the contractors, have it built and then charge everybody so we have the ability under our transmission owners agreement to do that right now. That's one avenue.

Ideally we want to make certain that the transmission gets built so what we're doing and I've directed our planning people to follow up on every project that we have in the transmission expansion plan and give me a report quarterly as to what the progress has been made on those things that were in the plan, are they being built? How are they going through the process of citing? Where are they at? Making certain that the utilities are actually doing what they said they were going to do in the plan so we get it done. We have to get the transmission and, if we just put together a plan and don't follow through on it, we're not doing enough.

CHAIRMAN WOOD: I just think we've got to move from the talking to the walking phase pretty fast.

MR. TORGERSON: We agree.

COMMISSIONER KELLIHER: Thanks for your presentation. I had a couple questions. One about the signing issue and a few about reliability. You just indicated the Midwest ISO could step in and build if the utilities declined to do so in your footprint?

TO: Yes, that's the final step.

COMMISSIONER KELLIHER: Is the Midwest ISO legally the authority that could seek transmission citing approval in all these states covered by the footprint?

MR. TORGERSON: That would be an interesting footprint because we haven't had to do it yet. We are a utility under the Federal Energy Regulatory Commission.

COMMISSIONER KELLIHER: But to seek state signing approval you have to be a utility under state law. I can understand the willingness to build but then there's a question of whether you actually could build. I'm just curious. Any kind of analysis you have of whether you would meet the definition of 'utility' under the various state laws?

MR. TORGERSON: We'd have to check that because we haven't had to do that yet. We have more than enough people who want to build but it's worthwhile pursuing that to make certain we could have that ability.

COMMISSIONER KELLIHER: Some of the reliability questions your presentation talked about applying the lessons learned but didn't really discuss what those lessons were. Could you briefly describe what the lessons learned by MISO were from August 14?

MR. TORGERSON: Sure, the things we saw were a lack of communication between let's say the Midwest ISO and the control areas or even the other RTOs that we've already addressed with communication plans and then putting in a new phone system. That's just the technology.

We really had to get the protocols down which we've addressed into when do you call, when do you send messages on?

We were putting in a messaging system. We have a messaging system. We're adding to it. So we can do a blast out that will get the people on the control area on the pagers which we have internally now. Any time there's a TLO our senior people get a message on a pager or through their phone or whatever that says "there's a TLR issue." We'll be sending that out to all the people that could be impacted.

The other lesson I think that we saw and I probably alluded to this, we didn't have enough coverage of the entire area. We were monitoring key facilities under the NERC guidelines. That's what it says, "key facilities."

My conclusion being not an engineer but best looking at it objectively is to say "we need to be monitoring all of the facilities not just ones that someone designates as key." We need to know what's going on everywhere.

That was the big lesson that I saw because we were monitoring key facilities but still lines were going down that we didn't see. That to me was the eye opener and it said "we've got to be monitoring all this."

So we're putting in place on our flow gate monitoring tool which is still used, we're going to have two major tools, the state estimator and the flow gate monitoring tool -- the flow gate monitoring tool will have information on every 230 kV line and above throughout the entire MISO footprint. The state estimator has information on all lines. Some of them go down to 69 kV but most of them 180 and above and then our alarming tool has everything that comes in from 100 kV and above so we really have three tools.

We've expanded this to make certain that the state estimator and the flow gate monitor are getting all the facilities that are important, not just the key ones. That was the other lesson that really opened my eyes from that.

COMMISSIONER KELLIHER: Have you all reached any conclusions with respect to control areas, what the right number of control areas is or is that still open?

MR. TORGERSON: I think that's still open. My opinion is it needs to be fewer. Thirty-five of them is way to many to manage. We're going to have to work with those who have the control areas and consolidate them and get down to a more efficient number. I don't know that one is the right answer because this is a very large footprint but it's got to be less than 35.

COMMISSIONER KELLIHER: I don't pretend to be an expert in the mechanics of the grid operation but I'm told that redispatch is one important tool if not the most important tool to assure reliability. Does the Midwest ISO have the authority currently to order redispatch?

MR. TORGERSON: Yes we do. In an emergency situation or where reliability is threatened we can order redispatch. That's in our transmission owners agreement.

COMMISSIONER KELLIHER: Did you do that on August 14th?

MR. TORGERSON: We did it, well not in the first Entergy area, we did when we were working with Cynergy and some other areas. We did order redispatch.

COMMISSIONER KELLIHER: THey complied?

MR. TORGERSON: Yes. It took a little time. I mean, it took some time to make it happen.

COMMISSIONER KELLIHER: But they did ultimately comply?

MR. TORGERSON: Yes and it wasn't Cynergy it was another party that was in the Cynergy area. I think it was an Allegheny subsidiary I believe.

COMMISSIONER KELLIHER: Just to be fair, you had authority to order redispatch once we suggested dispatch?

MR. TORGERSON: We have the ability to order. We have to make certain that people understand that, when we're talking about it, we're saying and the words that we have to use are "We direct you to start this generator and run it at X or bring this generator down and we have to actually direct them to do that.

And we do have real means to do that but you have to have sufficient knowledge to know that what you're doing is not going to exacerbate a problem.

So that was the situation we were pretty much in in the Midwest.

COMMISSIONER KELLIHER: My last question arises from the reliability meeting from last week. Last Monday the discussion was about the Western Electricity Coordinating Council model so-called contract model to assure adherence to reliability standards and my question is, whether MISO is considering making a similar filing that would use the contract model to make reliability standards enforceable?

MR. TORGERSON: We have not looked into that yet.

We were hoping that the energy bill would pass and it would make it mandatory so now we're going to have to rethink what needs to be done on reliability standards. I think we need to have mandatory reliability standards and what mechanism do we go through to make sure that that occurs?

I think the Commission is looking into it, at least that's what I understand. We may have to do something on our own.

You also have to remember we worked within -- there's three reliability councils that have jurisdiction within the Midwest ISO. We have MAIN and ECAR that have jurisdiction within the Midwest jurisdiction. We have MAPP, MAIN and ECAR.

Actually you pack this into the Southwest power pool which has reliability standards for that entire area, so there's the one that has standards. It's a matter of making sure that people follow them.

But in some cases, at least I understand it differs by resource adequacy. They're different from jurisdiction to jurisdiction.

COMMISSIONER KELLIHER: Thank you very much.

CHAIRMAN WOOD: On the control area issue that Joe raised, I've been to PJM and it's a different model there than ERCOT, where ERCOT actually got rid of control areas and there is one with a backup. PJM assumed in the umbrella a lot of the traditional control area responsibilities but the offices actually still remain in the classic PJM footprint that perform certain functions.

Is there a thought as to what actually MISO would do as control areas shift in their responsibility to the more regional approach? What is it that really has to happen first with regard to that sharing of control area functions that may not have been divvied up that way back in August?

MR. TORGERSON: We don't have any authority at the moment to even take over those responsibilities. They weren't given to us by the transmission owners when it was formed and then approved by the Commission. We have to go down that path first.

I think the PJM model is probably a good one. As you said, the control room operations really don't go away from the control area. They're still done at the local utility which is my expectation of what would occur, that they send a signal or a directive to that operator and tell them what to do with generation or load. That is kind of the model I would see us tackling. We are working with the entities within the Midwest ISO to start talking with them about how we can start transitioning and what changes should be made.

We haven't gotten too far yet. That needs to be done because without it you have very separate levels. The Midwest ISO can't control the generation which we will need to once we have the market. We need to be able to send that signal to tell people what to do.

That was something that will have to be incorporated into our market staff as to how that is going to occur, so when we file that in March we'll have to have a plan for how that will operate.

CHAIRMAN WOOD: I'll follow up on the question

Joe asked. I noticed from some trade press reports about the meeting that was held yesterday in Philadelphia on grid authority, grid condition issues, the headline said "in the aftermath of the blackout, top grid operating officials on Tuesday said that reliability coordinators must be able to order actions in real time during emergency conditions and that this authority has to be clearly defined before problems crop up with the power grid."

Is that something we need to do at MISO or is it done?

MR. TORGERSON: I think we need to make sure how we define how that works. I think we have the authority in an emergency situation where we have enough knowledge, we can order things to occur.

CHAIRMAN WOOD: If it's kind of a pre-emergency, which is probably where everything was that day.

\ MR. TORGERSON: You need to know ahead of time. That's the issue. You have to have sufficient knowledge to order something to happen. When we have the market, that's why the market will improve reliability because we'll be doing the security constrained commitment and economic dispatch so we'll know what's going on with each generator.

We'll be able to tell the generators what to do.

The other part of it is, when do you shed load?

We still don't have the ability to throw breakers and I doubt that we ever will to open and close the breakers, that will still be the job of the local utility. THey have their plans on what load to shed because you don't want to shed load for hospitals and police stations and so forth. We have to have those plans in place. Those would be the ones closest to the working system to go and make that happen.

But we will have to be in a position to tell them we need to shed 1,000 megawatts which we have the ability to do today. Again, you have to have sufficient information to be able to carry that out.

CHAIRMAN WOOD: To hop to that, you mentioned the improvements on page 6 of your presentation a moment ago. Some changes that had been made for the system wide monitoring and you gave a number currently the state estimator had 98 percent permission ability. Tell me what that means? Is it a good number? Is 95 good enough? Do you need it to be a hundred? What does that mean?

MR. TORGERSON: It means the solution solves successfully within the five minute period 98 percent of the time. If it didn't then you revert to the previous solution, the state estimator that it solved.

Our state estimator and continued state analysis, the state estimator right now is solving every 90 seconds. Our target now is to have it down to every 60 seconds. Then it does the contingency analysis using three solutions from the state estimator so that last three sought valid solutions, then it takes that and runs it into the contingency analysis and currently we're running against 5,500 contingencies and that occurs and it runs every six to eight minutes -- is about the time frame it takes to run.

But the 98 percent? Obviously I want it at 100 percent but you're not going to have a solution 100 percent of the time because the line may go out. That could cause a mismatch in the state estimator which won't allow them to get a valid solution. But as long as you have had valid solutions you can keep relying on that in the contingency analysis. It also then tells us if something needs to be looked at. That's the other reason.

So you have that, you want to see it and you go check it out immediately as soon as you don't have a valid solution.

CHAIRMAN WOOD: How many of those points that you've added are actually outside the MISO footprint?

MR. TORGERSON: That one I don't know the answer to.

CHAIRMAN WOOD: There are some?

MR. TORGERSON: Oh yes, for example, 30,000 buses that we have in our state estimator model, about half are in the Midwest ISO and the other half are outside so we go to the first tiers and we try to get within two nodes outside of the Midwest ISO.

CHAIRMAN WOOD: The part of that is just to make sure that everything that can impact your system external to the system --

MR. TORGERSON: We're picking up, yes.

CHAIRMAN WOOD: That's good. My particular issue, what if something is happening outside your system and you're not in charge of that? Actually I don't know if FirstEnergy is in or out of your system.

MR. TORGERSON: FirstEnergy was not a member at that point when we were doing the reliability coordination.

That was the only responsibility we had for them. They weren't a member at that point. They became one on October 1st.

The issue becomes are we getting the information from, let's say the next RTO over? That's why the joint operating agreement with PJM is so important. We are transferring information and data. We've got to look at how much do we need to have so we know it could impact our system. There's always going to be some judgment involved.

How far do you go 'til you see that you're getting enough to determine what the impacts are?

But if they see for example an occurrence happening they need to communicate to us. Now, we've probably gone to the far end now in communicating most things that are occurring. We want to let everybody know we've probably gone past what we maybe should need to be communicating. But I'd rather err on that side.

CHAIRMAN WOOD: That last thought, I'm remembering a pleading for rehearing which we dismissed because the energy markets tariff was actually just an advisory opinion -- are the issues between the transmission owners and MISO resolved about who's got authority to do what with regard to control area functions in both emergency time frames and non-emergency time frames?

MR. TORGERSON: In the emergency time frame it's in our transmission orders agreement. That one I don't think there's an issue. It has to get resolved ultimately with the market tariff as to what authority the Midwest ISO would and should have in relation to the control areas.

We have to put something in front of you and we'd like to work with out transmission owners to come up with an approach that we can all agree on but we need that at the time we actually go with the markets.

CHAIRMAN WOOD: You might have needed that last week. I'm not sure. I mean, you have to have it then. The other ISO, we've all kind of understood the ISO is continuing. Other than MISO, do you actually have the ISO or RTO as a NERC certified control area? That is not the case here in MISO yet, correct?

MR. TORGERSON: That's correct.

CHAIRMAN WOOD: It's your assertion that that should actually be the case to operate the Day Two markets?

MR. TORGERSON: We believe we're going to have to get there to be a NERC-certified control area operator. Again, what the relationship is within the control area, and the relationship with the control areas as they stand, has to be sorted out. But we're going to have to be in a position to work generation.

CHAIRMAN WOOD: In a non-emergency timeframe?

MR. TORGERSON: In a non-emergency situation, or the market won't function well.

CHAIRMAN WOOD: I'm personally interested to see that that issue -- I think we've got a pretty solid timeframe for the market implementation, which is well and good, but I don't know that that's the only reason that MISO needs to do it. MISO needs to do it to be a robust enough reliability coordinator to do this job.

I know that's not been a resolved issue by NERC yet, just because it hasn't faced it, but I've been following with substantial interest, the proceedings with the Blackout Task Force. When we drill down deep enough into this stuff, clear, direct accountability -- and you're the guy responsible and here's why, as opposed to the excuse we all have, it was not my authority. It happened to us once that we didn't have authority over reliability, but customers don't expect that answer to ever work a second time and we shouldn't either.

MR. TORGERSON: And we don't.

CHAIRMAN WOOD: We're here to buttress your efforts and sit down and address the legitimate needs of the existing control area operators, transmission owners or otherwise, to flesh those issues out fully and get them resolved. That needs to happen well in advance of December, and hopefully can happen before the summer.

MR. TORGERSON: I fully agree. Our plan was to have it in front of the Commission with our March filing.

CHAIRMAN WOOD: Perfect.

COMMISSIONER BROWNELL: Pat, you talked about this very issue on, if not August 14th, August 15th. I think what you're hearing us say is that this is critical, and if we can offer some adult supervision to help move those discussions along, we don't need death by a thousand cuts, and people kind of holding up the process for something else. This is exactly what you said, I think, right after blackout, are just non-negotiable. Maybe we should have been making that clear before.

So, please, yell if you need us.

MR. TORGERSON: I will do that.

CHAIRMAN WOOD: To repeat that thought, the concern was that the voluntary RTO formation that has led to what we have so far, I fear, has resulted in some compromises on both independence and reliability. I just want to commit us to make sure we don't make that mistake again and that we hold firm to the right principles in setting up ISOs and RTOs.

A final thought -- and it was actually two, I'm sorry. Stakeholder issues: Are we on track with the stakeholder process and OMS process, to ensure that when we file, we don't have the same response we did to the August filing? Is everybody taking the timeframe sufficiently seriously that we really are going to have this stuff done by Easter and then move it to the tariff process here at the Commission and let you guys get on with the testing and training issues? Or are we going to have these issues one year after the 3/31/04 filing?

MR. TORGERSON: People are working very actively to get these resolved. As you are aware, there are a couple of major issues. One is on the grandfathered contracts; one is on FTR allocation; and the control areas are going to be another one that we will see hammered out. Those are probably the three.

The grandfathered contracts, my understanding is that there has been a lot of progress made. That's tied to the FTR allocation, obviously, so there's movement. I think people are working pretty aggressively on it. I can't say for certain that by the time we get to March 31st and we want to have full consensus with everybody, I'd be surprised if that occurred.

Because you're talking about monetary issues, some decisions are going to have to get made. I think we're going to get a lot further along than we were this last time, and we will have -- the Midwest ISO will put forth the position that we believe is fair. That will be in our filing and it will be based on all the information we got from the stakeholders and all the issues we've heard. We have to tee up something.

CHAIRMAN WOOD: When I was at the Board, shortly -- I think it was at the time that you asked to pull down the tariff so that you could continue to work, and the two issues that I walked away from that meeting that needed to be resolved to get MISO kind of up and done were the footprint issues which, thanks to the events with IP and their recent announcement about joining MISO, and I assume the associated Ameren issues -- I mean to think through where the TransLink issues go in light of your information a moment ago.

But the footprint issues and the ability to work through the open issues on the markets tariff were the two I walked away with that were kind of my punch list items to work on. I just want to make sure that whatever we can do from the Staff and Commissioners' side to support that energy markets tariff issue moving along in the right timeframe with the right level of attention from all the interested parties, as much as possible -- I mean, to get unanimity is an unachievable goal, but to get a broad consensus is not, and I think we can work toward that.

Whatever we can do to help, we're committed to that. It's a top priority item at this Commission to get those discussions wrapped up and on track so that we can work through the Commission process here. But keep your eyes focused on getting reliability upgrades that you've laid out here, fully implemented and tested and then walk them through kind of the necessary allocation and responsibility issues across that very broad and important grid. We just want to keep your focus on that and have us do what we do.

But the delay questions, as Nora's question is putting out, are costing us all a bunch of money and that's not how customers want it.

A final question: Actually, I'm impressed with this business plan. It's exactly what, frankly, I look for as a regulator, and if I were a constituent out there, I would look for it in a professional organization. So, this has got the level of specificity, commitment, and analysis and understanding that I think a well run organization should have. So, congratulations on that, because I know from going through it that it's not just words, but a lot of this stuff is the distillation of what has been done and what is already well underway. So that's helpful.

To build up on one that we were talking about, and, I think, Joe, you brought this up, at the December 1st hearing we had on reliability, there's this operator training issue. Nora, I think you had some questions on this as well on.

Page 14 of the business plan talks about the training. I also noticed that in your presentation a moment ago, on the last page of the outreach goal, taking a leadership goal among all the RTOs on this issue. What kind of training goes on now? What's the enhancement that we're talking about doing?

These are a pretty critical part of our nation's economy. Since you're the first one here after that conference, tell us what kind of training goes on today and what really should be going on that is in your plan.

MR. TORGERSON: All of our operators are NERC-certified control room operators. They all have that designation. The ones that are in lead positions and the senior people, all have extensive experience with other utilities, actually running control rooms as reliability coordinators, because they all have reliability coordinator experience before they even came to us.

Then we did training with them on the MISO, our tariff, our requirements, I'll call it manuals and books that we have as to what they are supposed to do. So they have done all the training on that.

Where we need to go is, first off, we have a simulator. We haven't utilized it. That is one area that needs to be used. Every person has to go through the training.

What we've done is added shifts, so that every person has the ability through training every six weeks for a week. That's our plan.

Every person will be going through training on that schedule, including the simulator training. And the simulator, the only thing we have left to do with the simulator is put the scenarios into the simulator, make sure they work right, and run it off of our system.

They can train on that, so what will happen is, you have a supervisor, the trainer, running scenarios, and the operator will sit there and see a scenario coming up that says we just lost x-number of megawatts of flow over this line, and what are you going to do?

They actually have to act. That's the training that needs to be done.

The other training is also cross-training with the control area operators to make certain that we're talking the same way. We go and visit them, they come and see us, but when they see a situation that it's clear what we're both talking about, we're doing cross-training with all the control area, and the training may be just getting to know them, but it's getting to know their systems, their capabilities, what they do, what they can do from a reliability standpoint at the local level and what our responsibilities are.

We're also reinforcing what authority they do have. We do have the authority. They can tell someone to shed load; they can redispatch. They have already signed and they have done this in the past, a document that states that they know what their authority is.

We're reinforcing that part of the training, and what we're going to end up doing is having training protocols and programs that we believe will be far in excess of what NERC would even require.

And then we will certify all of our operators and reliability coordinators to standards that we have for the Midwest ISO. We're going to set our own standards for all of our operators, so when I talk about enhanced training, that's really what we're getting to.

CHAIRMAN WOOD: The plan for the enhanced training was complete it by December 1. What's your timeframe for actually implementing it?

MR. TORGERSON: First quarter, starting after the first of the year.

CHAIRMAN WOOD: Great. I appreciate that. I just got this this morning, so I'm going to keep reading it, but I appreciate your leadership on that, and your other constituents will as well.

I want to ask Chairman Young and Mr. Edwards if y'all have anything you'd like to add from the perspective of the independent board. We appreciate y'all being here today.

MR. YOUNG: It's kind of hard to add anything to what Jim said. Jim was very thorough, and obviously knows the system very well.

What I'd like to do is, from the Board, thank you for your support. It's been kind of a rough road for us getting started and we've had our ups and downs. We appreciate your support.

We understand -- and the Board has directed Jim very strongly, that the first thing we've got to do is get reliability right. I'm very pleased with what he's done. I spent 35 years in system operations with another utility, so I have some background in what goes on, and I think Jim and his staff have done exactly the right things.

I think they're doing them on a very aggressive timetable. I think you will be proud of the results, once it's all finished. Again, thank you for this opportunity to be here, and we're going to do our best to make you proud of what we do.

CHAIRMAN WOOD: Thank you, Mr. Young.

MR. EDWARDS: Mr. Chairman, if I may, just briefly, I want to thank the Commission for a couple of things: One is for your visits to the Midwest ISO headquarters. I think it's been beneficial, both for us as well as for you, but also for Mr. Clary and Mr. Miller's full-time support out there, to be lodged there, to be in our headquarters, to have access, it helps you all, but it also adds value to us as well, as well as Mr. Larcamp's attendance at our meetings.

Whenever you have a constituency process, there are so many different opinions. For your staff to hear those firsthand, I think adds a lot of value, both for you and for us. So we want to thank you for that, and also for your support of the Midwest ISO, and I reiterate what Chairman Young said; we will get it right.

I've always said that the worst thing is implementing a market that's not right. We will get it right and we will get it in on time.

MR. TORGERSON: I'd like to add one thing: I would like to thank you for the high level support we've gotten from the Commission and Staff. It has been the best thing we ever did, was to agree to have the two people, Patrick and Christopher, there.

CHAIRMAN WOOD: Two or our best.

(Laughter.)

MR. TORGERSON: I know that, but you offered them.

(Laughter.)

MR. TORGERSON: We agree. We're very thankful they are there. That relationship is phenomenal. The information flow, I think, is where it needs to be. We talk constantly. We know what's going on. We try to keep them informed and they keep us informed. It works both ways, but the support we've gotten from the Commission at the highest levels, we really appreciate and we need because of a lot of the issues we have going forward, so I want to thank you for that.

CHAIRMAN WOOD: Thank you all for your leadership. We follow with probably the most active of interest, what you all are doing. It's very critical to customers in a real broad swath of the country, and as you come into deeper integration with PJM and the JOA that we look forward to getting by the end of the month, we'll attest that you never can stand alone; you're always as good as your neighbor.

We really intend to help you and we'll be there.

Thanks for coming today. We appreciate it.

SECRETARY SALAS: The next item for discussion this morning is A-3, report on the New England Natural Gas Infrastructure. This is a presentation by John Schnagl, accompanied by Misha Bond, Camilla Ng, Raymond James, and Jeff Wright.

MR. SCHNAGL: Mr. Chairman, Commissioners, it's our pleasure this morning to brief you on the New England Natural Gas Infrastructure study. May I have the first slide?

(Slide.)

MR. SCHNAGL: Next one.

(Slide.)

MR. SCHNAGL: The Pipeline Safety Improvement Act of 2002, directs the Commission to evaluate the ability of New England's natural gas infrastructure to meet demands of electric power generation and to evaluate the ability of the natural gas system to meet all other current and projected demand.

(Slide.)

MR. SCHNAGL: New England has no native gas supplies. Natural gas is provided through the interstate pipeline systems shown in Figure 3, as well as through the

LNG import terminal in Everett, Massachusetts.

The source of supplies to New England are diverse, coming from both western and eastern Canada, from south central and eastern United States, as well as foreign sources through the LNG from Algeria and Trinidad and Tobago.

Next slide, please.

(Slide.)

MR. SCHNAGL: New England also has no underground bulk storage facilities. It relies on above-ground LNG facilities. Some of the peak shaving facilities are shown in this map. Next slide, please.

(Slide.)

Customers in New England also rely on bulk underground storage facilities in New York and Pennsylvania.

However, they must have capacity on interstate pipelines in order to bring the gas from these bulk storage facilities in New York and Pennsylvania, into New England. Therefore, they must have available capacity on that interstate pipeline system. Next slide, please.

(Slide.)

MR. SCHNAGL: Our examination of the load factors for the interstate pipelines during the peak demand periods shows that between December and February, the load factors on these interstate pipelines are quite high. As a region, the regional net load factor for December through February is well in excess of 90 percent. Next slide, please.

(Slide.)

MR. SCHNAGL: This shows a map of the United States during the peak month of January. This is actually a projection for 2004, with red highlights indicating the interstate pipelines with load factors in excess of 90 percent. This shows that while New England has a particularly high density of them, there are other areas of the country with high loading factors.

This does limit the opportunities for customers in New England to gain access to bulk storage. Next slide, please.

(Slide.)

MR. SCHNAGL: The natural gas used in New England has increased steadily since 1995 and is projected to increase through 2010. If one looks at this graph carefully, one sees that the residential, commercial, and industrial use is pretty flat.

If you go straight across there, it's a pretty flat line. The increase is pretty much due to the amount used for electric generation. Next slide.

(Slide.)

MR. SCHNAGL: This graph shows the relationship between natural gas used for electric generation, as well as the overall total amount of electric generation in New England.

While the amount of electric generation in New England has steadily increased, there's been some fairly significant increases in the amount of natural gas -- natural gas usage is indicated by the gold bars -- especially between 1998 and 2002, there was a sharp rise in the use of natural gas for electric generation.

This is caused by the construction of new gas-fired electric generation and it's pretty much ending here in 2003 and will pretty much be finalized in 2004. Right now, the electric reserve capacity is now up to around 22 percent in New England. Until that decreases, we expect little new construction of electric generation. Next slide, please.

(Slide.)

MR. SCHNAGL: There's been concerns in New England about the rapid rise in the use of natural gas for electric generation, so we wanted to take a look at it and compare it against the national average.

This shows the various NERC regions throughout the country, and it shows the U.S. average is just under 40 percent. That's pretty much where New England is, right around that national average, being approximately 38 percent. Next slide.

(Slide.)

MR. SCHNAGL: New England's electric generation capacity is fueled by many sources. This slide shows that between now and 2010, that capacity is expected to increase only marginally.

What I'd like to point out is that two separate bands, one, the salmon colored band, which is the gas and oil dual fuel band, is pretty constant with very little change.

These facilities can use either natural gas or fuel oil to fire electric generation. It's pretty much determined based on the economics.

The mustard colored band directly below it, is the gas-only facilities. These have expanded here recently, as you can see. It's important to note that these facilities must have natural gas in order to generate electricity.

During the conduct of this study, we were asked to investigate a concern that the ISO New England had, that the gas-only facilities were obtaining their natural gas under interruptible contracts and the ISO of New England was concerned that if the gas purchased under the interruptible contracts was, indeed, interrupted, that the ISO of New England would not have the capability of being able to supply electricity to New England.

So we set out to take a closer look at that. Next slide.

(Slide.)

MR. SCHNAGL: Figure 12 quantifies one of the contracts, the commodity contracts for purchase of the commodity of natural gas. There are two types of contracts used to actually acquire natural gas -- the commodity contract and the transportation contract. Both must be executed in order for a consumer to actually receive natural gas.

For the commodity contract, it shows that 61 percent of the contracts are firm contracts.

(Slide.)

MR. SCHNAGL: The next slide shows the results for the transportation contracts. This shows only 40 percent of the contracts are firm.

We assumed that those who purchase the more expensive firm contracts for transportation, backed it up with also a firm commodity contract, and, therefore, just doing the math, we assumed that only 40 percent of the gas-only electric generation had firm contracts.

Another way of saying it is that 60 percent of them, potentially, were interruptible, so we wanted to take a look and see what would happen if 60 percent of the gas-only electric generation was not operating.

This graph basically shows the bottom line of that computation. The first column on the left shows the base condition with all facilities operating with essentially all gas facilities available. It shows an operable capacity margin, very healthy at 5,725 megawatts. If 60 percent of the gas-only facilities are taken off system, that operable capacity margin drops to 1,225, a sizable drop.

However, in order to meet peak demands, you only need a positive operable capacity margin, so what this is showing us is that even with the loss of all interruptible gas-only facilities, the ISO of New England has sufficient electric generation capacity to meet its needs on a systemwide basis.

This is not to say that there wouldn't be portions of New England, especially the very isolated areas, RMR areas, that are dependent on single gas-only generation facilities that may have service interruptions.

(Slide.)

MR. SCHNAGL: We also took a look at New England's ability to transfer electricity in from other areas. This slide shows the transfer capabilities for both Canada, as well as ISO New England.

We found New England had a very healthy ability to transfer as much as 12 to 14 percent of its peak demands for electricity between this capability and its own native generation capacity, we felt that New England currently has very good ability to withstand curtailment of interruptible gas supplies, at least for short periods of time.

Next slide, please.

(Slide.)

MR. SCHNAGL: In order to evaluate the ability of existing capacity on the pipeline system to meet current demands as well as projected demands, we put together this graph, which shows pretty clearly that relationship.

The straight red line indicates exiting capacity; the blue line indicates demand, current and projected demand. Let's focus on those two to start with.

You notice that exiting capacity is more than adequate to meet current and projected demands up through 2005. However, in 2006, demand exceeds capacity.

Once we saw that happening, we went back and looked at the projects that either this Commission has already certificated that are yet unconstructed or other proposed projects with scheduled completion dates in the near term. We looked at the LNG expansion, as well as pipeline expansion, and potentially also the new LNG terminals that have been proposed.

We added to the capacity line here, those new projects based on when the proposed completion date is. Once we did that, it became very clear that with either certificated, unconstricted projects, once they come online, or the projects, when they are constructed, the capacity will stay ahead of projected demand, at least through 2010.

CHAIRMAN WOOD: John, what specific projects are those, so that we can keep an eye on that and keep everybody focused on these issues, so that those two lines stay apart?

MR. SCHNAGL: The LNG expansion that has already been certificated is the existing Everett project. We also have an expansion proposed, at least in the trade press, by Keyspan, of their Providence facility.

The pipeline expansion is the Freedom Trails Project, which would bring gas in from the west, from the bulk storage facilities.

CHAIRMAN WOOD: Is that approved or pending?

MR. SCHNAGL: That is still pending.

CHAIRMAN WOOD: Who is the Applicant?

MR. WRIGHT: Excuse me. That project is still planned. It has not been filed at the Commission yet, but it would be expected within the next year or two to be filed here.

CHAIRMAN WOOD: 1/06?

MR. SCHNAGL: Yes, it's still scheduled for 1/06.

CHAIRMAN WOOD: Back to the LNG expansion, the Keyspan LNG expansion is, again, what project? Does it require approval?

MR. SCHNAGL: It's the Providence facility and it would require our approval, and it's scheduled for completion in early 2005.

MR. WRIGHT: The Providence LNG facility is a current storage facility, and, as such, the tanks are in place. It would just need docking facilities for the boats.

CHAIRMAN WOOD: Okay. Then the last, so the new LNG terminal on the right-hand box, is different than that?

MR. SCHNAGL: The new LNG terminal is different.

There is a host of options, as we'll explain in the next slide, as to which may fit into that.

It basically comes down to, if one doesn't, another one will.

CHAIRMAN WOOD: How many will be needed for that curve to go where it does in 2008?

MR. SCHNAGL: Just one.

CHAIRMAN WOOD: In addition to Providence and Everett?

MR. SCHNAGL: That's correct. There is also one other factor that can be included in this, and that's probably a host of new proposals that we will see for integration of existing pipeline systems, in some cases intrastate pipeline systems, to achieve what interstate pipeline systems are currently doing.

Currently before the Commission, is a new proposal by New England Gas and Yankee Gas Service to basically link the systems together to achieve interstate transport of natural gas from the Algonquin system.

I think that is a very innovative type of approach to solve some short-term problems, and I think it's one that we'll see many more of.

CHAIRMAN WOOD: That's filed here now?

MR. SCHNAGL: It is.

CHAIRMAN WOOD: What's the status?

MR. SCHNAGL: I don't know. I can check on that when I get back.

(Slide.)

MR. SCHNAGL: Just to give you some sort of perspective on the number of LNG facilities that are currently either proposed or pending somewhere before the Commission, I wanted to provide this graphic to show you that not only are there a number of proposals out there, but also we have some expectation of having additional gas coming in from the Sable Island Area.

Depending on the timing of the development of that supply, that supply could be replaced by LNG facilities up in Nova Scotia and still result in a new supply of natural gas coming into New England from eastern Canada. Next slide, please.

(Slide.)

CHAIRMAN WOOD: We've got to get basically two of these to happen to make that curve right, one of them perhaps being the expansion and then one other one.

MR. SCHNAGL: The Everett facility is currently expanding. That's underway. The proposed Providence LNG expansion is not here yet, but it's something we feel is a pretty high probability event here. And Keyspan is well underway. They have discussed filing with us, and will not require much in the way of new construction.

And there are also a number of others -- the Fall River Cove Project, the Somerset in Massachusetts. They are all competing projects. They are proposing new construction of facilities for new terminals.

MR. WRIGHT: I'd just like to note that the Weaver's Cove is under our NEPA prefiling agenda, so we are already analyzing the Weaver's Cove facility and should add that to the Fall River and Somerset, because it should be Fall River, Weaver's Cove, and Somerset.

(Slide.)

MR. SCHNAGL: Figure 18 shows the expected work flow analysis for natural gas in New England. It basically shows snapshots from the 2004, 2007, and 2010 periods.

The major difference between 2004 and 2007 is the increase in LNG coming into the New England region, but by 2010, we see an additional supply coming in from Eastern Canada. Next slide, please.

(Slide.)

MR. SCHNAGL: The Act basically asks us for recommendations on how to improve the existing natural gas infrastructure in New England, so for the short- and mid-term, we observe that peak-shaving storage facilities located in the vicinity of high demand areas, would provide the greatest short- and mid-term system benefits.

For the long-term, however, as supply areas in Eastern Canada are further developed or additional LNG terminals are constructed, additional natural gas pipelines will be built to supply the New York City area.

Interconnection of these new onshore pipelines with New England's existing pipeline and LNG facilities would be a long-term solution, thereby increasing the gas pipeline infrastructure to meet New England's long-term natural gas supply needs.

Thanks very much. We'll be happy to answer questions.

CHAIRMAN WOOD: Thanks again. Any questions?

COMMISSIONER BROWNELL: Very helpful.

COMMISSIONER KELLY: I have a question: How did you estimate demand?

MR. SCHNAGL: We looked at a variety of sources in terms of identifying demand. We worked directly with the Department of Energy to obtain numbers concerning demand. We also contracted with a group called Energy and Environmental Analysis, EEA, which we relied on heavily for their demand numbers.

We basically did an independent evaluation of anything that we received from the outside. We received a tremendous amount of input regarding this study from the public utility commissioners and commissions in New England, ISO New England, as well as all the industry groups up there, so we received a tremendous amount of valuable input in the development of this study.

COMMISSIONER KELLY: Thank you, John. Is this the first issuance of the report? Has it gone out to anyone before the Commission seeing it today?

MR. SCHNAGL: It has gone out to nobody.

COMMISSIONER KELLY: Thank you.

MR. WRIGHT: It's going up to Congress today.

MR. ROBINSON: We did have basically the results of the study and we presented it to the people in Boston who would be most affected by this. We had 50 or 60 people there who gave us comments on our study and the results of it, and we incorporated that in this final report.

But as far as a report going to Congress, this is the first issuance of this report, because it is a report to Congress.

COMMISSIONER KELLY: Staff has done an excellent job, and I really appreciate it, thank you.

CHAIRMAN WOOD: Thank you all very much.

SECRETARY SALAS: The next item in the discussion agenda is E-4, New England Power Pool.

MR. HUYLER: Good morning, Mr. Chairman and Commissioners. In this Order, the Commission approves a proposal submitted jointly by ISO New England and NEPOOL to allocate costs associated with transmission upgrades.

The Order also rejects the complaint that an alternative approach to distributing grid costs. The approved allocation method is applicable to transmission methods that have been identified through the ISO's regional transmission expansion planning process that are not participant-funded.

The allocation method provides regional cost support to upgrades that produce network-wide benefits. The costs of upgrades that provide only local benefits will be supported locally. For those upgrades receiving regional cost support, costs will be rolled into the regional transmission rate paid by all network customers.

Upgrades considered necessary to ensure reliability would receive regional cost support, as would upgrades determined by the ISO to provide a net economic benefit to the region as a whole. Generally, upgrades related to generation, interconnection, and merchant transmission facilities would not receive regional cost support.

Also, upgrades or additions rated below 115 kilovolts or those rated above 115 KV that do not meet certain non-voltage criteria, would not receive regional cost support.

The cost allocation method also contains a provision to protect against rolling unreasonable costs into the regional rate. Such costs could include construction of transmission lines underground.

ISO New England filed their proposal with the Commission following an extensive and inclusive stakeholder process. The proposal was approved by a vote of almost 78 percent of the NEPOOL participants committee, which is broadly representative and made up of five sectors: Generation, transmission, supplier, end user and publicly-owned entities.

The Order states that RTOs and ISOs are in a unique position to discern regional needs and address factors inhibiting the investment in transmission and generation. The Order recognizes that the New England grid is highly integrated and the needed reliability or econonic upgrades on one part of New England's grid provide benefits to other parts of the grid, both immediately and to changing beneficiaries over time. The Order finds that these factors support the regional choice made here.

This concludes our presentation. We will be happy to take questions.

CHAIRMAN WOOD: Questions or comments?

COMMISSIONER BROWNELL: You talked about the stakeholder process. Is there an RSC, a Regional State Committee, yet for New England?

MS. FERNANDEZ: No, there isn't one that's been formed yet. NECPUC, the New England Conference of Public Utility Commissioners, has traditionally taken a very active role in the NEPOOL and ISO New England proceedings, and they were involved in this.

I understand that there have been discussions of coming up with an RSC that would include appointments by the Governor, that may go beyond some members of the state commissions, but that's still in the process of being developed.

COMMISSIONER BROWNELL: There was not consensus among the state commissions themselves. About half did not support this proposal.

MS. FERNANDEZ: There was no consensus among the state commissions.

COMMISSIONER BROWNELL: I'll just say this: This was a very tough one for me. We had, I think, some intense conversations. The balance are committed to regional deference. We emphasized regional deference, particularly to two regional/state commissions, and in the absence of one, that's difficult.

I believe absolutely that socializing the cost of reliability is important and, frankly, it would be easy to kind of wave that reliability around and pretty much say everything is as they seem to have done here. What I was troubled by was the lack of a rigorous economic analysis of the kind Jim Torgerson referred to in MISO in trying to really delve down into the details of beneficiaries.

It's not easy. We all know that the beneficiaries change over time, but I don't think we can get stuck on that.

In addition to regional deference, we've also talked about cost causation and how we really are going to exercise some judicious evaluation in determining that.

I can't support the Order. I would have supported the alternative. I hope that we are able to encourage the market participants and their RTOs and the ISOs to do a more rigorous analysis. I don't know that we've found the perfect model. It's very difficult, but I don't think this gets us where we need to go, so it was a real tension between regional deference and cost causation.

CHAIRMAN WOOD: Joe?

COMMISSIONER KELLIHER: I support the Order. I thank Staff for the description. The proposed amendments would provide the transmission upgrades that produce regional benefits and receive regional cost support. Those upgrades that provide only local benefits receive local cost support. That is an approach I support.

I have just one question: In Paragraph 38, there is some discussion about the difficulties in siting, state and local siting difficulties, and I was just curious if Staff has information now or later about, of the six states, how many of them bar consideration of benefits to neighboring states in their siting process?

My understanding is that something like 25 state laws bar consideration of benefits to neighboring states. I'm just curious about how that breaks out in New England.

MS. FERNANDEZ: I think that's something we need to check on.

COMMISSIONER KELLIHER: Great, thank you.

COMMISSIONER KELLY: I also support the Order.

It's clear that the vast majority of participants supported this. If you look at the other significant number of how many participants opposed on a pure vote cast, only eight percent of the participants opposed this, and on an adjusted basis, only 13 percent opposed it.

There was no consensus in the states. In fact, a number of the states supported it. There was apparently not an economic analysis done before adopting this, however, I would hope that subsequent to the adoption of this methodology, NEPOOL analyzes the impact that it has on infrastructure development.

I know we did not put that in our Order. We talked about it. I would like to communicate to NEPOOL that I hope they undertake that study.

CHAIRMAN WOOD: I also support the Order. I think that in the interest of getting transmission construction, which has been identified through a brilliant, ideal process, it's probably year ahead of the one we heard about in MISO, but an objective, engineering-based, need-based review of the whole grid goes on in New England every year and forms the RTEP.

The RTEP then determines which are reliability upgrades. I don't know that any of the two plans that we've seen, yet have identified or have studied upgrades, just for congestion or other economic reasons, but those could conceivably be redone in the same process.

This is an issue that I raised a moment ago with MISO. It's important to be able to move from the discussion and planning phase to the construction expansion, energizing phase.

I think our assessment -- and we articulated it very clearly in the SMD proposal, and, more so, I think, in the white paper in April -- is that the investment community needs the certainty of knowing what the recovery formula will be. So, quite frankly, congratulations on New England for giving us two pretty clear answers.

We'll pick one here today, but what's important for the rest of the country is that they do a similar type step. It's a hard one; it's not popular, but it just shows you how hard these are.

But it is important to arrive at a formula, adopt it, and get there. Don't look back. I think they committed, in another proceeding, that this will take place every five years or at least be revised in five years, at which time I think that we'll have a full blown RSC performing the duties.

But for the certainty of constructing needed transmission, there is no more important thing to do than to decide on the cost allocation methodology and to adopt it and move it along.

I appreciate the discussions we had, the hard work you all did. Some of us actually went back to New England for some further questions back in October and I'm glad we did, because it helped inform the process, but I do think it's time to make these decisions and then get with it.

I'm ready to vote.

COMMISSIONER BROWNELL: I cannot support the Order.

COMMISSIONER KELLIHER: Am I supposed to say "aye" now? Aye.

(Laughter.)

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next matter for discussion is E-64. This is PJM Interconnection, with a presentation by Diego Gomez, accompanied by David Kathen, Michael Goldenberg, and Alice Fernandez.

MR. GOMEZ: Good morning, Mr. Chairman and Commissioners. E-64 addresses PJM interconnection LSE's filing in Docket No. EL-3-236, to amend tariff sheets pursuant to Section 206 of the Federal Power Act to revise the upward price gap rules for must-run generating units and to establish a local market option to address long-term scarcity.

PJM also proposes to amend the operating agreements and PJM tariff to require that all owners of generation located in the PJM region become members of PJM or otherwise agree to abide by all PJM rules regarding generation and transmission.

The issue of how to price must-run generating units has arisen not only in PJM, but other regions. Accordingly, the draft Order establishes a generic proceeding in Docket Number PLO2-4 and directs Staff to convene a two-part technical conference. The first part of the conference will focus on broad, general principles for must-run generating units and the general framework the Commission should use to address this issue.

The second part of the conference will focus on PJM's specific proposal in Docket Number EL03-236 and how it fits within the broader framework. This conference will provide a useful regulatory framework for reviewing various regional proposals for treatment of must-run generating facilities. Thank you.

CHAIRMAN WOOD: Thank you, Diego.

COMMISSIONER BROWNELL: I'm grateful, actually, Mr. Chairman, that you have scheduled these conferences. This is an issue of compensation and equity and fairness.

We have been struggling with it and, brilliant though we are, we don't seem to have come up with the right answer. I'm a little bit concerned that PJM has come in with a tweaked solution that doesn't really enjoy much apparent stakeholder support, so I'm hoping that in both Day One and in the broader sense, in Day Two in the very specific regions, we can really hear some creative ideas that bring some stability to this market.

It's really troubling that this keeps bubbling up everywhere in the country. So, thanks.

CHAIRMAN WOOD: I really do think even it's eclipsed resource adequacy in the capacity markets. The issue of local market power mitigation is one or probably two of the big ten issues on the standard market design that we've been studying for two years that really I don't kind of feel, when I sit down and read these Orders, whether it's the RMR case in New England, or what California wants to do in its mitigation -- that we really have this really well put together.

The real fight that we have with all these other issues on congestion and expansion, reliability and pricing and things like that, this one is just not quite there, so I do look forward to really rolling up some sleeves in January and plowing into this, because it's not resolved.

I have to admit that I was expecting, I guess, in this particular PJM filing, based on the Reliant versus PJM complaint we had in the summer and their comments, which then led to the formation of a within-agency task force to talk about local market power mitigation, which is going to culminate in these conferences now, that we would have gotten a little bit more to work with in this docket.

This may be enough. I don't know if it is, so I want to not only focus on the PJM issue, but try to look at it in the context -- one of the things that the whole RTO week and the whole development of the public debate we've had on standard market design for the past couple of years has done, it has allowed me, at least, to get comfortable with these are the broad kind of objectives of what we're doing and these are some specific things or a specific thing that will accomplish those objectives that has worked here, overseas, or in some other market.

And so having that real-world experience to inform on where to go, has contributed to a lot of wise decisionmaking on our part, and also some wise proposals from the market participants across the country.

This is one area where I just don't quite think we've figured it out yet, so I look forward to new hands on the deck, as well as some wisdom from the outside world on this.

COMMISSIONER KELLY: I appreciate your saying that. If you think we have a ways to go in figuring it out it makes me feel a little better about my personal decision not to participate in several cases on the agenda that involved RMR feeling personally that I didn't understand in any significant way the policy implications of the various choices or even what the various choices are.

I personally appreciate and look forward to having these technical conferences. Obviously it's an issue in PJM, NEPOOL, I hope that we get some participation from ERCOT and California, who obviously have dealt with the same issue. Thank you.

CHAIRMAN WOOD: Anything?

COMMISSIONER KELLIHER: I support the order. I agree it's time to take a hard look at the different approaches on local market power mitigation. I just had one question for Diego in paragraphs 8 and 13, there's some discussion about how one of the four changes PJM is seeking is authority. THey want to be able to compel. They are proposing to amend their operating agreement and tariff to require generation owners to become PJM members.

I"m just curious what their legal authority would be to compel the generation owner to become a member?

MR. GOMEZ: PJM as the transmission operator has the right to establish "just and reasonable" rules with regard to parties when they want to use its system. The specific language that you referred to specifically states that "the party may either choose to become a member of PJM or agree to abide by its rules regarding transmission and generation.

So on its face the language proposed as, but it doesn't specifically compel, the parties to become members of PJM.

Having said that, the draft order doesn't substantively address any issues and sets the issues for hearing and this is one of the issues staff anticipates will be raised at that conference.

COMMISSIONER KELLIHER: You said that that authority would be an authority the Commission has previously issued approving a tariff? If they can either require membership or adherence? What would they point to?

If a generator said "I'm in PJM and I don't want to join PJM. I don't want to abide by your rules," what would PJM point to to say "you can't do that?"

MR. BARDEE: I think at least preliminarily the feeling by me and some people on staff is, they would certainly have a priority to tell someone if you want to take transmission service from us, you have to live with the rules we have in our tariff that ensure that this system will operate safely and reliably.

They phrased it as, "you can become a member or you can abide by our rules." If all they had said was, "you have to be a member of our organization" I think there would be some serious legal question about their ability to impose that or our authority to approve it.

But because they've stated it all tentatively that you either become a member or abide by the rules in the tariff, I think there's at least at this point a good legal argument in their favor.

COMMISSIONER KELLIHER: They would be complying with the Commission's approved tact?

MR. BARDEE: Right.

COMMISSIONER KELLIHER: I understand, thank you.

MR. BARDEE: They would accept this ultimately.

COMMISSIONER KELLIHER: Thank you.

CHAIRMAN WOOD: Ready to vote?

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

I would like to add this is probably going to be market power month. We are looking at a two day conference on the supply margin assessment on the 13th and 14th so if we schedule around that, I think the local market power mitigation in conjunction with all the generation market power issues will pretty comprehensively broach the market power subject by this time next month.

All right, next item?

SECRETARY SALAS: The next item on the discussion agenda is E-3, the transmission congestion on the Delmarva Peninsula.

MS. MARTIN: Good afternoon, Mr. Chairman, Commissioners, Ladies and Gentlemen.

This presentation summarizes the findings of fact and recommendation issued on October 10, 2003, by Presiding Administrative Law Judge Bobbie McCartney in Docket number PLO3-12-000 concerning transmission congestion on the portion of the power grid on the Delmarva Peninsula by PJM.

14

(Slide.)

That's PJM and in the lower right hand corner, light brown, is the Delmarva Peninsula.

(Slide.)

Since 1998 PJM has used locational marginal pricing to manage congestion. Under locational marginal pricing, prices are higher in areas that do not have low cost generation and a transmission infrastructure that restricts imports.

Delmarva has experienced higher congestion costs due to these limitations on generation and import capability.

(Slide.)

Congestion on Delmarva Peninsula has been an issue in several PJM proceedings including a complaint filed by Old Dominion Electric Cooperative requesting relief from congestion charges, transmission planning process for economic expansions, allocation of financial transmission rights, and local market power mitigation measures.

(Slide.)

As a result, on May 12, 2003, the Commission established a fact finding proceeding concerning congestion on the Delmarva Peninsula to explore the causes, extend costs and possible solutions to such congestion.

On October 10, 2003, the ALJ issued a decision that proposed findings of fact and recommendations.

(Slide.)

Congestion on the Delmarva peninsula is a pricing issue not a reliability issue. This is a summary of her findings. LMP reveals congestion rather than causes congestion. Congestion was highest in 2000 and 2001 due to temporary outages, due to construction of transmission facilities, limitation on generation and transmission contribute to the congestion costs.

(Slide.)

As a result the ALJ recommended that PJM should consider changes for scheduling transmission outages. If defective transmission construction on locational marginal pricing institutes or considers instituting posed contingency operations, PJM should expedite transmission planning for the Delmarva Peninsula. PJM should periodically conduct auctions for demand resources and generation.

(Slide.)

The record does not support an allegation that, or allegations that market power increased congestion costs.

PJM's mitigation measures and active monitoring limited opportunities for exercise of market power.

As a result, the ALJ recommended that the Office of Market Oversight Investigation review the record for evidence of the existence and extent of market power on the Delmarva Peninsula.

(Slide.)

Subsequent to that, PJM and ODEK filed an agreement on November 6 on the process to address congestion. The stakeholder process to review potential changes to the PJM market rules. PJM will file to implement its independent recommendations by May 3, 2004. PJM will file changes not approved through the stakeholder process.

(Slide.)

In conclusion, congestion has been reduced on the

Delmarva Peninsula. More infrastructure generation, transmission and demand response would reduce congestion, need cooperation with states and PJM to place infrastructure in place.

This concludes our presentation. Thank you.

COMMISSIONER BROWNELL: So we've concluded definitively according to the judge's summary that LMP is not the cause of congestion nor the cause of high prices and that FTRs can and should be used as effective hedging tools and there seems to be some suggestion that maybe that wasn't done.

Should one of the suggestions be that we ask PJM to do a more extensive job of educating the market participants on the effective use of FTRs, would that perhaps be helpful?

MS. MARTIN: They have actually instituted, extended, added training programs as a result of this. I think they said this in their comments.

COMMISSIONER BROWNELL: Okay. You indicate here "congestion has been reduced on the Delmarva Peninsula but more infrastructure is needed." How much? What has been done and what needs to get done?

MS. FERNANDEZ: Part of one of the judge's findings was that the worst congestion occurred in 2000 and 2001. That was a period when there was a lot of construction. There was additional new generation. There was transmission that was put in both to serve that new generation and there also have been some other measures that are going on in terms of expanding transmission.

In terms of what needs to be done in the future, this is an area where it needs to import power. So there may need to be a continuing look at whether transmission additions need to be added, whether demand response can help reduce the need for power.

As part of the economic process that the Commission required the PJM adopt as part of its RTO filing, it will be looking at areas to determine if it would be economic to do construction in order to help relieve congestion areas like the Delmarva Peninsula.

Additionally we recently had a merchant transmission proposal that would also, by I think having a line across the Chesapeake Bay, would also provide a way to provide additional power and more flexibility to the region.

COMMISSIONER BROWNELL: I think this speaks to the mind that you introduced in the first business plan. We need infrastructure. We can dance on the head of a pin but if there isn't infrastructure, this is the result.

So I would hope that PJM and the folks in Delaware would make this a priority -- tell us what we need to do but more importantly I hope.

And I appreciate the judges' work here and the staff's work, that we would use this as lessons learned.

I think it was in fact used to suggest some lessons that in fact are not borne out by findings of fact so I hope everyone will be instructed by the Judge's finding and we can be effective partners in fixing this problem.

COMMISSIONER KELLY: I understand the judge was not looking at reliability but I was wondering if any of those issues came up during this case on the Delmarva Peninsula that you otherwise know about?

MS. FERNANDEZ: I thought her finding was that there was sufficient generation and transmission capacity to meet the reliability requirements and under PJM's planning process there has traditionally been an annual review and plan that's developed looking forward for several years if there are any needed expansions that are necessary for reliability.

However, a lot of the generation that is located on the Delmarva Peninsula tends to be more expensive. Some of that is because of limitations on the type of fuel that can be used in there. That's why I think her finding was it's more of a pricing issue -- it may be cheaper to import power from other parts of PJM but it's pricing rather than reliability.

Thank you.

COMMISSIONER KELLY: Thank you.

CHAIRMAN WOOD: I notice we do have -- we will be discussing this further internally and may initiate further actions as a result of this so I just want to thank Val and Alice and Mike and the rest of the staff for their public presentation and thank Judge McCartney for her work in kind of a nontraditional format that I hope we'll use again, as we need to really try to get on some of these stories that go out and about around the industry and find out exactly what is going on so we can do something about it.

So after all we've learned here we may take additional actions, as I believe were recommended here and we'll do that at a future time. Thank you.

SECRETARY SALAS: The next matter is E-2, PJM interconnection.

MR. CARTER: Good afternoon.

In Agenda Item E-2 the Commission addresses a settlement agreement filed by PJM Interconnection, LLC, and certain of PJM's transmission owners. The settlement agreement proposes to resolve the remaining issues pending in connection with PJM's establishment in 1997 as an independent system operator.

First the settlement agreement proposes to allocate the Section 205 filing rights of PJM and PJM's transmission owners, specifically the settlement agreement proposes to allocate to PJM's transmission owners filing rights regarding rate design matters, filing rights related to terms and conditions of PJM's tariffs will be allocated to PJM.

In a case of a dispute about the allocation of filing rights that cannot be resolved informally, the settlement agreement proposes that the dispute be resolved by a neutral party. The neutral party's decision would be binding and final.

The settlement agreement also proposes that it's terms be subject to Mobile Sierra protection, with revisions to the allocations to the filing rights under the settlement agreement could not be made by PJM or by PJM's transmission owners on a unilateral basis or by the Commission absent a Mobile Sierra public interest showing.

The settlement agreement also proposes to modify the rights of PJM's transmission owners to withdraw from PJM specifically the settlement agreement proposes to eliminate the existing requirement that a transmission owner as a condition of it's withdrawal from PJM receive Commission approval. The draft order approves the settlement agreement as it relates to the settling parties's division of their respective section 205 filing rights.

However, the draft order modifies that portion of the settlement agreement precluding Commission review of a neutral party's determinations regarding filing rights disputes. The draft order finds that interested parties must be permitted to have recourse to the Commission on the issue of whether a particular matter is related to rate design or related to the terms and conditions of PJM's tariff.

In addition the draft order modifies the settlement agreement as it relates to a transmission owners' rights to withdraw from PJM. In particular the draft order notes the withdrawal from PJM can only be effectuated pursuant to a revision of the operating agreements giving rise to PJM.

Accordingly, the draft order finds that withdrawal from PJM must be subject to a section 205 filing.

Thank you.

CHAIRMAN WOOD: I think that letter point is very important, particularly just the legal aspect of the agreement itself is involved that would be the underlying transmission owner agreement. But as a matter of policy we certainly saw, with the MISO issues, that it is extremely destabilizing to these very critical organizations, questions of who's in, who's out, where's the footprint, doesn't change when somebody gets mad because the independent operator actually operated independently.

However the reliability for markets I think it's very important and almost a minimum condition that this Commission have the opportunity to agree under the Federal Power Act on anybody's decision to withdraw from participating in an RTO.

The court I think pointedly noted as it was pointed out here in footnote 38, the court did not adjudicate enough, PJM transmission owners did not contest FERC's authority to review a specific withdrawal under section 205.

So we quite frankly are doing here what the court invited which is to make sure that, although it concluded and again I think in error, but it concluded and we'll stand on the books, that we cannot review that under 203, that we do have that right under 205.

And I think quite frankly the obligation under 205 to ensure that any changes to membership in these very critical organizations for reliability oversight and for market operations are reviewed as against the public interest standard by this Commission.

I think the rest of the agreement actually is a fair balance. I do acknowledge that this changes if not the word the spirit of order 2000 with regard to the right to operate the tariff by the independent ISO or RTO.

But I think the allocation of the money issues to TOs and the market to PJM is right. It's the right place to be. Ultimately we get to pass on al that so the buck does stop with us.

Again I think it's very important to the sustained reliability and independent operation of these organizations that the Commission have a very involved oversight role as our modifications to their settlement would indicate.

So I support the order. And we're ready to vote.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: AYe.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item is E-5, Oklahoma Gas and Electric Company

MR. HUNGER: I'm David Hunger along with Jim Akers and Julia Lake. Good afternoon.

Today's draft order addresses the request for Commission authorization under section 203 of the Federal Power Act for the acquisition of jurisdictional facilities associated with MRGs, 77 percent interest in the McClain Generating Facility by Oklahoma Gas and Electric. The draft order sets for hearing the issue of the proper mitigation of the increase of the OG&E's horizontal and vertical market power resulting from the acquisition.

The McClain facility is located in the OG&E territory. Applicant's analysis of the effect of the acquisition on competition shows failures of the Commission's horizontal competitive analysis screen in the OG&E market. Applicants have proposed mitigation, a transmission upgrade, which would reduce market concentration by increasing the scope of the relevant market. This form of mitigation will take approximately 18 months to complete.

The draft order finds that, until this transmission upgrade is in place, interim mitigation is required. This finding is consistent with the Commission's merger policy statement. The Commission stated that interim mitigation is required to address the harm to competition indicated by screen failures until permanent mitigation is in place.

The draft order also finds that the acquisition would harm competition by increasing OG&E's vertical market power relating to the control transmission facilities necessary for access to wholesale markets. It finds that OG&E has the ability to use this transmission system to frustrate competition in wholesale markets by denying rival suppliers access to the market and the acquisition of 400 megawatts of generation will increase OD&E's incentive to do so.

Interveners have submitted a number of proposals to mitigate OG&E's vertical market power. The draft order sets for hearing the question of the appropriate mitigation.

This concludes our presentation and we would be happy to answer any questions.

CHAIRMAN WOOD: Thank you David.

Any comments or thoughts?

COMMISSIONER BROWNELL: This is one of those other tough issues that we've been struggling with as the industry I think responds in some cases to the chaos of the last couple of years by reintegrating.

It's certainly important that the company be able to serve native load. At the same time I think it does raise both horizontal and vertical market power issues.

I don't think this is going away and I'd like to see us, and I'll be writing in a separate statement, just really deal with the issue of vertical market power in a generic proceeding, get some dialogue going on and really refining our policy so people know exactly what to expect.

There are some very specific things here dealing with horizontal market power but the real issue is how are we going to move forward rather than backward, which some of these activities I think cause us concern.

I support the order. This is really important to get our arms around to send the right policy signals from this organization as we talk about certainty. Here's what to expect. Here's what we're going to ask you and here's what the policy is going to be going forward.

CHAIRMAN WOOD: I guess the only thing I would add here is, I know probably a lot of you here in this room worked a lot with the prior Commission on this merger policy statement that has really informed what goes on under

Section 203 applications.

We've actually seen very little of it in the last couple of years, but that hard work indicated that mitigation to address failures in the generation market screens and/or -- which were more specifically laid out in that statement than some of the vertical issues and I share your distinction there. We require mitigation in advance of approval of the transaction. I don't know that the Commission has been quite as consistent on requiring that to be done in advance of approval for transactions, so I would hope that folks reading this will understand that we are implementing the policy statement that we put out several years ago.

COMMISSIONER KELLY: I am persuaded that the question of appropriate mitigation both interim and permanent cannot be determined fairly based on the record as it currently stands and that it is appropriate for the draft order to direct a hearing into these issues. So I support the order.

CHAIRMAN WOOD: Let's vote.

COMMISSIONER BROWNELL: Aye, noting my concurrence.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: Next we will take up two matters, G-1, Northern Natural Gas Companies, and G-3, Centerpoint Energy Gas Transmission Company. This is a presentation by Mr. Richard Howe.

MR. HOWE: Good afternoon.

The draft orders in both G-1 and G-3 address pipeline proposals, to amend their tariffs so as to permit them to offer discounted rates based on formulas. The formulas could include the use of the difference between the gas commodity index price at different points on the system commonly referred to as 'basis differentials.'

In the G-1 order the Commission originally rejected a proposal like this by Northern Natural Gas Company. However the U.S. Court of Appeals for the District of Columbia Circuit vacated the Commission's orders holding among other things that the Commission had not adequately explained the difference between discounted and negotiated rate transactions.

The G-1 draft order finds that the fundamental distinction between discounted and negotiated rates is that discounted rates must remain within the range established by the pipelines' maximum and minimum recourse rates and discounted rates must reflect the same rate design as the recourse rates but negotiated rates are not subject to either of those restrictions.

The draft order accordingly finds the rate formulas that produce varying rates during the term of an agreement are permissible as discounted rates so long as the rate remains within the range established by the maximum and minimum rates set forth in the pipeline's tariff.

The G-1 draft order also finds that basis differentials may be used in discounted rate formulas. The draft order recognizes that the Commission's July 25, 2003, negotiated rate policy statement modifies Commission rate policy to no longer permit the use of basis differentials in negotiated rates.

The draft order also recognizes that requests to reconsider that policy are currently pending before the Commission. However, the draft order finds that regardless of the approach the Commission ultimately takes with respect to the use of basis differentials in negotiated rates, any concerns about the use of basis differentials in negotiated rates that were set forth in the July 25th policy statement are not present in the context of discounted rates.

This is because discounted rates unlike negotiated rates are capped at the pipeline's maximum cost of service rate. Consistent with the G-1 draft order, the draft order in G-3 approves the tariff proposal by Centerpoint Energy Gas Transmission Company similar to the Northern Natural proposal approved in G-1.

Finally both draft orders do require that the pipelines revise their proposed tariff language in order to ensure that any formula based discounts do use the same rate design as the pipelines recourse rates.

Thank you.

CHAIRMAN WOOD: Thank you, Richard.

As the one who I think had the greatest heartburn and certainly of the current Commission about the basis differential pricing in the past year, really as was filed in the TransWestern docket almost two years ago, I would like to point out a sentence in the G-1 order right after what Richard was reading because discounted rates unlike negotiated rates are capped by the pipeline's maximum cost of service rate.

Any concern about basis differential pricing giving the pipeline an incentive to withhold capacity in order to achieve higher revenues then would be possible and its maximum cost of service rates should be less in the discounted rate context.

I think this is actually intuitively sensible and borne out to be correct.

My continued concerns about basis differential pricing which are really at the heart of the concern I have about the pipelines getting back into the commodity business after this Commission worked so hard over the last 15 years to really force that divorce to happen -- are really minimized here.

I think if a shipper and a pipeline want to agree on this type pricing it appears from some of the comments that we've received that there is quite a bit of that. It's a useful tool in the financial hedging of prices for commodities.

I think we should do what we can to facilitate those transactions so I appreciate your urging that over the past several months and I hope that the parties can with the cap implemented as a discounted rate invoke the G-1 and the G-3.

The other one is similar to that, right?

MR. HOWE: That's right.

CHAIRMAN WOOD: And will facilitate those transactions. So I support these two orders.

COMMISSIONER KELLIHER: Mr. Chairman I support G-1 and G-3 as well. I just wanted to ask a question and make a brief comment.

The question is, G-1 in paragraph 11 refers to how the court invited the Commission to establish what they apparently describe as a coherent definition of what the negotiated rate, the definition of discounted rate policy -- are we essentially adopting the Northern Natural definition?

MR. HOWE: Yes we are.

COMMISSIONER KELLIHER: Just a comment -- both orders do have some discussion of the July 25 policy statement on negotiated rates and I just wanted to express my reservations about the policy statement and indicate that I tend to agree with what Commissioner Brownell has said on this issue.

That's it.

CHAIRMAN WOOD: Which could probably explain why G-2 was struck.

(Laughter.)

CHAIRMAN WOOD: It is my hope that, despite that, it will be interesting to hear about it from the industry. If parties really think that a loan has to come through with a discounted rate with the maximum recourse rate cap on it do not provide sufficient flexibility to accomplish legitimate financial hedging opportunities for customers, then I think we're open to hearing that. It is my hope that the G-1 and G-3 fix is enough and we can all just kind of live with that. If not, we're big boys and girls and we can take comments and hear what parties have to say.

COMMISSIONER KELLY: Mr. Chairman, I agree with your wise comments.

(Laughter.)

CHAIRMAN WOOD: Let's vote. If anybody would ask me later why was G-2 struck, there's your answer. It's fun to be a foursome isn't it?

(Laughter.)

CHAIRMAN WOOD: Thank you all. Have we voted? We haven't voted.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

And that was on both.

SECRETARY SALAS: On both items.

CHAIRMAN WOOD: Thank you.

SECRETARY SALAS: The final item for discussion this morning is G-4, Carter's Grove LSB, a presentation also by Richard Howe.

MR. HOWE: This item concerns two other agreements for transportation that were attached to a complaint. The letter agreements governing the shippers rates for firm and interruptable transportation, the two shippers, LSB Cottage Grove and LSB Whitewater, have filed a complaint against Northern Natural which alleges that the pipeline was improperly billing certain surcharges.

The shippers have requested confidentiality for the letter agreements so that currently they are not available to the public.

The draft order before you concerns the letter agreements themselves rather than the billing dispute because the letter agreements raise concerns beyond the particular billing dispute between the parties.

The letter agreements appear to contain material deviations from Northern Natural's pro forma service agreement which were not filed with the Commission or made public. In addition the letter agreements appear to contain some provisions that are contrary to the Commission's regulations and policies.

Accordingly the draft order does three things all of which are just procedural. It provides the parties an opportunity to comment on whether the letter agreement should be made public.

Next to that it asks Norther Natural for information concerning the letter agreements and, finally, the order asks Northern Natural to show cause why certain provisions of the letter agreements are lawful.

Thank you.

CHAIRMAN WOOD: I don't have much to add other than I'm concerned that this has been going on and we haven't been able to see it due to the fact that the utilities have not met their obligation apparently to file certain documents with the Commission.

So I look forward to hearing what the good reasons for that may be and see where we go from there.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

Meeting adjourned.

(Whereupon the proceeding adjourned at 1:00 p.m.)