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

856TH COMMISSION MEETING

OPEN MEETING

Commission Meeting Room
Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, D.C.

Wednesday, April 14, 2004
10:10 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

ALSO PRESENT:

DAVID L. HOFFMAN, Reporter

P R O C E E D I N G S

(10:10 a.m.)

CHAIRMAN WOOD: Good morning. This open 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.

Let's begin with the Pledge to our Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Before we start our business today, I want to congratulate Suedeen and also thank the President for doing as good a job the second time as he did the first in announcing your reappointment this week. We're all happy for that.

On a sadder note, I do note that the former Solicitor of the Federal Power Commission, Howard Mohrenback, who was 100 years old, passed away in the past couple of days. He had been here for 30 years in the Federal Power Commission, and was Solicitor of the Agency from 1957 to 1967.

So, we send our best thoughts to his daughter, and pause to remember all the people who made this Agency great.

Madam Secretary?

SECRETARY SALAS: Good morning, Mr. Chairman;

good morning Commissioners. The following items have been struck from the agenda since the issuance of the Sunshine Notice on April 7th: E-8, E-9, E-24, E-36, E-38, E-55, G-14, and G-22.

The consent agenda for this morning is as follows: Electric Items - E-5, E-10, 11, 12, 13, 15, 16, 18, 20, 21, 22, 23, 25, 26, 28, 32, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 52, and 54.

Gas Items: G-2, 3, 4, 5, 6, 7, 8, 9, 11, 12, 16, 17, 18, 20, 23, 24, and 26.

Hydro Items: H-1 and H-2.

Certificates: C-1, 2, and 3.

Specific votes for some of these items are as follows: As required by law, Commissioner Kelly is recused from the following cases on the consent agenda: E -20, E-26, E-44, E-45, E-49, G-3, G-11, G-18 and G-24.

As to E-28, Commissioner Brownell is dissenting; E-52, Commissioner Kelly is dissenting, in part, with a separate statement; and G-2, Commissioner Brownell concurring.

Commissioner Kelly votes first this morning.

COMMISSIONER KELLY: With the exception of the recusals noted by the Secretary and my dissent in E-52, I vote aye.

COMMISSIONER BROWNELL: Aye, noting my dissent on

E-28 and concurrence on G-2.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The first item in this discussion agenda this morning is a presentation of the Blackout Report of August 14, 2003. This is a presentation by Alison Silverstein who is the Senior Policy Advisor to Chairman Wood.

MS. SILVERSTEIN: Can we get the PowerPoint up on the screen, please?

(Slide.)

MS. SILVERSTEIN: Good morning. Although I have a number of pages in the Powerpoint, we're going to zip through them because I know you all have read every page in this report in the few days that it's been out, and I thank you for that, as do the 300 other people who worked hard on this with us.

I'm going to go very briefly through the final report of the blackout investigation. We're going to talk about the blackout and the sequence of events, the investigation itself, our findings on how the blackout happened and why it happened, and then the recommendations of the report.

(Slide.)

MS. SILVERSTEIN: Going to page 3, please, the blackout occurred on August 14th, 2003, starting, for all intents and purposes, at 4:05:57 Eastern Daylight Time in Ohio, and expanded from there. Over 50 million people were out of power in the Northeast U.S. and Canada; 62,000 megawatts of load lost and millions of work hours and billions of dollars in economic costs -- that's both U.S. and Canadian dollars.

A reminder that President Bush and Prime Minister Chretien created an international task force to work on this. Chairman Wood was one of the members of that task force. There were three teams set up to work on this task force: One of them on the electric outage itself, one of them on security issues, and one on nuclear issues.

I was privileged to co-chair the electric system investigation, and I would give you a reminder that we had the opportunity and the input to work with over 200 experts from across the U.S. and Canada, reflecting companies that are electricity providers and transmission owners, RTOs, ISOs, equipment suppliers, staffers from NERC, the U.S. and Canadian governments.

Slide 5, please.

(Slide.)

MS. SILVERSTEIN: In the review of what happened, you recall that from the initial investigation and our interim report, we explained a number of computer problems and other things. None of those findings have changed.

They have, however, been supplemented, so just to review very briefly, there were a significant number of computer problems that contributed to and exacerbated people's inability to identify what was going wrong. These occurred at both MISO and primarily at First Energy.

Slide 5 just reviews some of the juicer moments of the computer failures. Slide 6, please.

(Slide.)

MS. SILVERSTEIN: There were a number of reactive power problems and increasing voltage problems across the Cleveland-Akron area. These became worse at 1:31 Eastern Standard Time when First Energy lost East Lake 5 plant, which is a significant reactive power source for the Cleveland-Akron area.

First Energy, we found, did not have enough of an understanding of the system and the voltage problems and characteristics to understand just how severe the consequences were for this. Slide 7, please.

(Slide.)

MS. SILVERSTEIN: This demonstrates -- it should demonstrate -- unfortunately, we seem to have a PowerPoint glitch. In your handout, you cannot see, but there is a big yellow blob over the most important information that this is supposed to demonstrate, but happily, on-screen, this shows you that voltages were falling, both throughout the day and in the days previously, so you can see that, as a normal pattern in the course of events, as load goes up, voltages go down.

But until the afternoon of the 14th in the Cleveland-Akron area, you did not have significant reductions in voltage below a safe operating level, although they were coming close. Slide 8, please.

(Slide.)

MS. SILVERSTEIN: First Energy began significant line outages starting at 3:05, then lost three, 345 lines in the period of time between 3:05 and 3:41, Eastern Daylight Time in the Cleveland-Akron area. It's critical to note that these lines are under normal loadings and under appropriate line carrying capacity.

They were lost specifically because the lines were contacted by trees that were too tall and had not been adequately trimmed, so this wasn't a matter of lines being overloaded and beyond their carrying capacity.

So, with each successive line loss, line loading shifted and reactive power demands increased.

Following the first two of those lines that were lost, the reactive power problems began increasing. Starting at 15:39, FE began losing the underlying 138-KV system in this area, so more and more customers were being cut off without service during that period. It was sort of a self-inflicted blackout. On to page 9, please.

(Slide.)

MS. SILVERSTEIN: The tipping point for the entire blackout occurred at 3:57:05 when First Energy lost the Sammis-Star 345-KV line. This was the fourth of the 345-KV lines to go down, and it was the first of the lines lost on a true overload, rather than a tree contact.

This ended up cutting out a major path of power imports into the Cleveland-Akron area, and was the starting point for the full cascade. Slide 10, please.

(Slide.)

MS. SILVERSTEIN: For those of us who managed to escape all the hard parts of physics and electrical engineering in college, a cascade is a dynamic phenomenon, if you say it properly, in an electric system, that can't be stopped by human intervention, once it starts.

So the whole point of the cascade is, once it gets going, get out of the way. This one started at 15:57, but the bulk of the action in terms of the line losses and things going black within the Northeast and Canada, started at about 4:05 and by 4:12 it was all over.

That's a pretty short period of time, seven minutes, during which the bulk of the damage occurred. What happened through the cascade was that a series of power swings, voltage fluctuations and frequency fluctuations caused sequential trips of a number of transmission lines and generators and automatic load-shedding in a growing geographic area.

The system oscillations grew so large that the system could never re-balance and stabilize.

(Slide.)

MS. SILVERSTEIN: If you go to Slide 11, we have a little cartoon here that shows how things started. The yellow arrows indicate the paths where electricity was moving, and you see the black lines indicate where the lines to transfer power were lost.

As successive lines and the little gray blobs indicate, this area is blacked out, so what you see is that the black bars indicate lost transmission paths are expanding over time; the gray blobs that are blacked out are increasing over time, and the power flows are adjusting with every single one of these.

The system did not turn dynamic and on retrieval until the panel labeled No. 3, which is in the top right corner -- what you see then is how everything sort of expanded very quickly, within just a few minutes, to crash and crater.

(Slide.)

MS. SILVERSTEIN: Slide 12 shows the location and the causes -- would, if you could see it in full size -- of the 265 power plants that were lost. This, too, is organized in time slices, so that we can better understand what happened and how things accumulated over time.

(Slide.)

MS. SILVERSTEIN: Turning to causes, let's go to Slide 13, please. The Ohio phase began for five reasons, one of which is derivative. The first is that First Energy and ECAR, which is its Regional Reliability Council, failed to study and understand the inadequacies of the First Energy system. Because of those failures, First Energy was not operating the system using appropriate voltage criteria.

Second, First Energy had inadequate situational awareness because of its computer problems, among other things, and didn't recognize its system deteriorating from about 1:00 on. Next slide, please.

(Slide.)

MS. SILVERSTEIN: Third, First Energy failed to trim the trees in its rights of way so that each of the early 345-KV lines faltered on a tree that was too tall and MISO and neighboring PJM were not able to provide effective real-time diagnostic support to First Energy, and when they did try, First Energy didn't take the hint.

Fifth, because of all of those other causes, First Energy did not act to restore its system to a secure condition in the timeframe before 3:57 when it might have made a difference.

Why the Cascade happened. Slide 15, please.

(Slide.)

MS. SILVERSTEIN: There were four causes here, too: The first is sort of an obvious one; the Sammis-Star trip and the Cleveland-Akron line trips shifted the load burden onto paths that weren't able to carry it.

Secondly, after Sammis-Star, a series of Zone 3 and a few Zone 2 relays in Ohio and Michigan caused a series of line trips between 15:57:05 and 16:10 that would not have happened so quickly, had those relays not operated, so had those relays not triggered so quickly, there might have been significantly more time to bring this back.

CHAIRMAN WOOD: Define that a little bit better, Alison.

MS. SILVERSTEIN: A relay setting -- a relay is the element -- I may have to call upon some of my technical experts if you ask me one more question beyond this -- but a relay is an item that is connected to your circuit breakers and the relay is the guy that says this is exceeding the parameters and I'm tripping this off.

CHAIRMAN WOOD: Were they set at a pretty fine tolerance?

MS. SILVERSTEIN: Zone 3's and Zone 2's set to act line Zones 3's. The Zones are how far out it's looking on the length of the line. Zone 1 covers within the span of the line and goes out 50 to 70 percent; Zone 2 goes out almost to the other end of the line in terms of looking across the breadth of the line to see a fault. Zone 3's are called overreaching relays because they look at a Zone that looks beyond the length of the line into the next segment of the line and says if there's something out there, I'm going to cut off to protect this line, this length of line.

So there were a number of Zone 3's. Most of these were set to reach out 150 percent, so they're looking halfway into the next length of line, and these Zone 2's in Michigan were set to operate like Zone 3's and were, I think, at over 200 percent of the line.

CHAIRMAN WOOD: Why would you set a Zone 2 to be a Zone 3? Just to be ultra-conservative?

MS. SILVERSTEIN: I don't know. I have never set a relay, but there's years and decades invested in relay philosophy. The folks who set those Zone 2 relays have since changed the settings, though.

CHAIRMAN WOOD: That's why the Michigan Commission is taking those steps.

MS. SILVERSTEIN: It's worth noting that there has been a point of discussion that Zone 3 relays had an impact in the '60s on the first Northeast blackout, and after that occurred, significant portions of the country stopped using Zone 3 relays on 345 and extra high voltage systems, so Zone 3's are now primarily used outside the Midwest on the 138-KV system and below.

The point is, they're set with almost no time delay, so if it sees something, it's going to trip pretty quickly. The point is that because these things did not see actual faults, what they were responding to was the mathematical calculation that made it look like the overload that they were seeing made it look as though they were seeing a fault within the Zone 3, so they tripped on that.

The relay did absolutely the right thing, but the consequence was the wrong thing. It was one of those good decision/bad outcome things that always bites you.

(Slide.)

MS. SILVERSTEIN: If we go to page 16, the third finding in terms of the causes of the cascade was that the relay settings on the lines, the generators and the load-shedding across the Northeast were not coordinated and they were no integrated in a way that would reduce the likelihood of a cascade, so the grid's elements and regions couldn't re-balance.

What happened essentially was that you had the swing take out a whole bunch, upset a lot of generators that then took seconds and minutes to grind down to a halt.

At the same time, pieces of the transmission system were experiencing those and their relays were shutting down. Then you had load-shedding going on, and so everything was sort of seesawing back and forth and the system never had time to re-balance and settle out in a way that would either preserve the system as a whole or preserve larger chunks and islands as intact operating units.

Again, it's the idea that everybody set things in way that made sense individually, but when you look at this particular set of characteristics, things didn't occur effectively.

It was basic physics. Once all this stuff started, there was no way to shut it down, and the grid couldn't recover. Slide 17, please.

(Slide.)

MS. SILVERSTEIN: Moving to recommendations, the report contains 46 recommendations that we sorted in a number of groups. The first batch were institutional issues. This included 14 recommendations. I have listed several that should be among your favorites.

These include making reliability standards mandatory and enforceable; developing an independent funding mechanism for NERC; strengthening the effectiveness and the organization of reliability institutions, including NERC and the Regional Councils; and defining minimum requirements and cleaner footprints for control areas and for reliability authorities.

MS. SILVERSTEIN: -- making it absolutely clear that reliability investments should be recoverable in transmission rates.

Next slide, please.

MS. SILVERSTEIN: There are a number of very specific action-oriented recommendations, 17 of them, in fact, mostly focusing on the NERC recommendation of February 14, 2004.

These include a number of ones to address and correct the direct causes of the blackout -- strengthening NERC's compliance program, supporting NERC's reliability readiness audits, improving operator training and certification, using better system protection measures, using better real time tools for grid monitoring and operation, and accelerating and improving the adoption of meaningful, enforceable, compliable reliability standards.

Next, please.

MS. SILVERSTEIN: Thirteen recommendations on physical and cyber security standards and two that are specific to the operation and design of Canadian nuclear plants.

Next slide, please.

MS. SILVERSTEIN: The system is manmade, so it is almost guaranteed that more blackouts will occur. And because this system is subject to mechanical failure and human error, we can pretty much guarantee that more blackouts will occur.

Our goal, however, is to make a better set of mistakes and to contain the magnitude of the next blackouts. NERC's readiness audits are a key preventive measure. In that regard I would note that 11 of those have been conducted to date. They are targeted to cover 80 percent of the load within the United States.

I apologize. I don't know the load in Canada that would be covered by this. And on those audits we have at least one and usually two FERC engineers participating in the NERC sponsored audit team on every one of those reviews.

Last, I should note that the U.S.-Canada taskforce has been extended for a year to provide oversight for the implementation of the recommendations that we just reviewed. Chairman Wood, as a member of that taskforce, will be hip deep in that action.

Thank you very much.

CHAIRMAN WOOD: Thank you, Alison. Any questions for Alison?

(No response.)

CHAIRMAN WOOD: That was the foundation for the two action items that the Commission has on our agenda today.

After that we're going to ask Alison to come back and talk about some internal changes that we've done in the light of our enhanced appropriation for this current fiscal year on the FERC side and talk about the reliability team. We'll do that after we do the two orders.

Joe.

COMMISSIONER KELLIHER: Alison, you pointed out in your summary that some of the recommendations relate to making reliability standards clear and enforceable, but the final report is pretty critical of NERC in this area.

It points out, first of all, that the standards are vague, but also says that "NERC was aware of the lack of specificity and detail in some standards, but they moved slowly to address the problems effectively."

I understand that over the past two years NERC has been able to issue one clear reliability standard.

MS. SILVERSTEIN: They have issued one standard adopted ironically on August 15, 2003, and it addressed cyber security, which happily was not a contributor to this blackout. However, NERC adopted the ANSI accredited process for standard development. But it is a fairly slow -- was a fairly slow thing. They were not possessed in a sense of urgency until after August 14th. But they have been aware that something needed to go faster at the March NERC meetings.

And I think since then the board of trustees has approved the schedule. And I'm not sure about the board of trustees, but NERC has agreed. The membership of NERC has agreed to adopt a significantly expedited schedule to put a new set of standards in place that are far more quantifiable, measurable, able to be complied with, and able to be enforced.

Those are currently on schedule to be adopted and voted on no later than the end of December. Now it will be the standard version one. Those will have something in place. Those will be based, by the way, in part on a set of compliance templates that were adopted to make the whole compliance audit process more effective.

FERC's own Mike Oliver from the auditing department was a critical member of that taskforce as a professional auditor. He has a great deal of experience in what you need to do to something to make it worthy of and clear and unambiguous. So Mike's contributions were important on that taskforce.

COMMISSIONER KELLIHER: You're referring to December of this year?

MS. SILVERSTEIN: Yes. What they will probably do is take the bulk of them, the evolution from standards, the old standards, policies, requirements. There's a whole suite of things with a bunch of different names, very few of which were standards in the sense we would like them to be.

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They are being morphed in terms of their basic content into something that is auditable, measurable, worth complying with. Those will then be improved. So it's like making the thing you've got seaworthy before you go buying or renovating it. So it's just bringing it, so it's just bringing it up to pass the inspections.

COMMISSIONER KELLIHER: The final report seems skeptical of the new FERC process as well.

MS. SILVERSTEIN: No, our job was to talk about the -- well, was it August 14th?

COMMISSIONER KELLIHER: It does say development of standards as lengthy and not yet fully understood or applied. Whether this process can be adopted remains to be seen. So it seems to be skeptical of the new schedule they've outline.

MS. SILVERSTEIN: That was written before the new NERC schedule was adopted. Our job is to talk about the process as it existed through 2003. Our job is not to take shots about where NERC is now going.

COMMISSIONER KELLIHER: What it is recently about the reports that the report is referring to?

MS. SILVERSTEIN: The recently adopted process is two years old. It was the whole NERC schedule.

Understand none of that changed until March 23 or

24, so NERC has done a heroic job of changing, morphing, and bringing itself up to speed and agreeing grimly that it is necessary to do a much a faster and more thorough job at standards revision.

When this was written, the schedule they were working on was to adopt 17 standards by December of 2006. Given the usual pace of committee work, we could have expected that to slide.

COMMISSIONER KELLIHER: This portion of the April 5th report predates the March 15th.

MS. SILVERSTEIN: March 24, yes.

CHAIRMAN WOOD: By "recent," you mean recent when NERC reconstituted itself with an independent board and adopted the ANSI process back in the '01 timeframe.

MS. SILVERSTEIN: Yes, sir.

COMMISSIONER KELLIHER: One last question. Assuming Congress acts and reliability standards are enforced, then we need standards that are clear enough to actually be enforced.

How many standards are we talking about in terms of order of magnitude? Is it dozens, scores, hundreds?

MS. SILVERSTEIN: I don't know. That is something that the industry needs to re-examine. They developed the current set of shopping list of standards in a previous time and it was pre-blackout. And one of the things that this agency is going to be doing and the reliability team will be doing -- working with the U.S. and Canadian governments through the Department of Energy and the Canadian Department of Natural Resources -- is to talk to NERC and the industry and to take a more formal overview of what has been learned from the blackout and the investigations and how do we need to rethink the standards, the process, and the contents.

So that is not something that people have yet had time to do.

COMMISSIONER KELLIHER: Do we know, whatever the number of standards we wind up with, when might we have clear, enforceable standards?

MS. SILVERSTEIN: The first batch will be available at the end of December 2004.

COMMISSIONER KELLIHER: Then the final batch -- any notion?

MS. SILVERSTEIN: If NERC and the industry do the job that needs to be done, there will never be a final batch. They will always be improved over time.

COMMISSIONER KELLIHER: My point of finality is not that they be written in stone and never change. Finality from my point of view is clear enough to be enforced while giving due notice. I'm expecting that they be changed over time.

MS. SILVERSTEIN: The intent of the group that developed the compliance templates and the clear expectation from the batch that should be adopted in December is these are able to be enforced. It is no more of the lack of clarity and the fuzzy, ambiguous "able to interpret it in five different ways."

One of the points of us having experts within the FERC staff who are members of those committees and able to kibitz on the processes is to make sure that our people are part of these processes and able to say, "Here are ways we could get around that. Let's try tightening up here."

So our folks will be part of the process contributing along with the many others in the industry who are committed to having good standards because they know they need them to make sure the other guy's system doesn't take them down.

It's not as though we're working alone on this. There are many in the industry who recognize the need and are working hard to get to the right place.

COMMISSIONER KELLIHER: As I understand, we'll get our first installment of clear standards and then we don't know when future installments -- in December. And we don't know when there will be future installments and when we'll get to a final installment.

MS. SILVERSTEIN: I don't personally know the answer to when the final installment will be due, but I'm sure I'll have an e-mail from NERC on my computer upstairs and we'll be able to respond to you before the end of the day.

COMMISSIONER KELLIHER: Thank you very much.

COMMISSIONER BROWNELL: Can I just kind of build on the line of questioning that Commissioner Kelliher was pursuing?

The report identifies some systemic institutional problems with the organization and the way it's funded. There was quite a -- disturbing actually -- discussion about the way the regional councils are funded and their interrelationship and dependence on the very companies they are intended to oversee and that I suspect probably contributes to the lack of ECAR's willingness to really do an accurate assessment.

Therefore, I think if you really look at those broad systemic problems, why would you believe this is a brand new world and, yes, we'll get the first batch because you've got a big report out here.

And I hope the first batch includes the issues that were issued in the last seven blackouts, which is pretty astonishing to me. I would have had those ready to go off the shelf maybe several years ago.

But what happens now in terms of that? If we get the language that's in Congress, does that deal effectively with the issues of institutional change? Am I understanding this now that NERC has no public process for putting people on notice when they have failed some kind of a test? How do we deal with the transparency? How do we get to independent audits?

I often say if my kids had been able to give themselves their own report cards, they all would have done a whole lot better than they did. Bright as they are and as well as they did.

How do we break this? What I think is a very unhealthy relationship?

MS. SILVERSTEIN: One thing that we can do right now without waiting for legislation that is contemplated in item E-7 is to rethink the funding of the NERC organization and to make that an independent thing that does not go through the utilities and does not go through the regional reliability councils.

More broadly though, NERC, too, and the industry recognize the governance issues that you're talking about. And there are a couple of things that are being done.

I will note that on, I think, April 6 the NERC board approved and released the disclosure guidelines for both the reliability readiness reviews and the compliance audits that were being conducted. The compliance audits have been conducted only within the regional reliability council of its members. And most of the audit results were never shared publicly at all.

That will be changing. The reliability readiness reviews are a new critter. Those reports are being produced as we speak and will be posted -- are being posted on the NERC Web site and are completely accessible by the public and by regulators including us.

Many companies we are hearing across the industry and are talking to a number of managers and CEO's who are taking the findings of this report and recognizing the changes that need to be made are responding very aggressively in terms of implementing a bunch of the recommendations here.

Institutionally I can see the NERC board and membership changing their positions. It is not easy. Not everybody wants to do it.

But there is a growing recognition of the need for speed and of the need for change in terms of the way in which they invest and the way in which they reveal and accept the consequences and lack of good behavior. And there is far more industry support both privately and publicly for these changes.

COMMISSIONER BROWNELL: I'm glad we've worked together. And I'm glad we've made progress. But it seems to me we haven't made a lot of progress since NERC was founded.

I am pleased that the group that you're involved in, Pat, is going to continue for a year. I don't think we can afford to hold the American public hostage to the inability of us to provide leadership to get this done.

I testified in Pennsylvania before a senate committee talking about reliability. And I have to tell you, the questions were quite penetrating and they were quite mystified as to why we find ourselves in this position.

Candidly, I was hard pressed to provide some good and credible explanations. I am glad we're taking this here. I really appreciate the work of all of you in doing this, but I think this is an ongoing process.

The sense of urgency that Commissioner Kelleher I think was pressing for needs to be present every single day.

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MS. SILVERSTEIN: You all had something very important that can help to keep the pressure on -- and that's called the bully pulpit. I encourage you through your speeches and through measures like these orders to continue using it to keep the heat on and to keep this action moving.

COMMISSIONER BROWNELL: I just have one more comment. I read that the nuclear system -- I know their recommendations for Canada.

But the nuclear system operated as we might have expected and we can confidence. And we had a good visit with the NRC -- that the appropriate mechanisms are in place to assure that that safety issue is already at work.

This is not one of the things we need to do although continuous improvement is needed. Is that correct?

MS. SILVERSTEIN: Yes, ma'am.

CHAIR WOOD: Suedeen Kelly.

COMMISSIONER KELLY: In the latter half of the 90's FERC issued orders numbered 888 and 2000. Pursuant to those orders a number of transmission systems and control areas have organized into regional organizations.

Some of these regional organizations have instituted markets, day-ahead markets and real time markets. In addition, in the last eight or so years a number of states, including some of the states affected by the blackout, have instituted retail choice in electricity.

In the final blackout report none of these were structurally mentioned as causes or contributing factors to the blackout? Is that correct?

MS. SILVERSTEIN: Yes, it is.

COMMISSIONER KELLY: Is there a way or are there suggestions as to how these regional organizations that are formed as part of the restructuring might be part of the solution?

MS. SILVERSTEIN: Yes. Let me modify -- in addition to answering that, let me modify my prior answer. We answered in chapter 4 the specific issue of competition and markets and said that there are so many issues related to that that it is impossible and inappropriate to merely say competition did this. Rather demands grew significantly. Generation grew significantly. Transmission grew hardly at all.

Therefore, so many things were changing during the period that competition was being implemented that it is wildly inappropriate to blame competition alone for a potential diminution in reliability.

More specifically, we recommend that a detailed study be done so that the questions about competition and its impact on reliability be put to rest. However, it is our observation that while not having studied it in detail, it appears that systems have implemented two things.

One of them is a large, professionally managed, well trained regional transmission operator or independent system operator are much better at running a system and have a higher class of tools and a better set of operators and just overall are paying a lot more attention to the business of running the grid reliably and have greater capabilities to do that day in and day out.

So it is the personal view of myself and many of the people who worked on this investigation that you will experience better reliability inside an RTO or ISO than you will outside one because they are better able to deal with the basics of reliability.

Second, when you end up in an organized market, particularly when it is using a locational marginal pricing, you end up with much more effective signals for where investments need to be made and where grid congestion is getting tight.

There is often a relationship between congestion and reliability -- potential reliability problems so there is far more attention, commitment, and involvement actively rather than passively by the market participants that we believe leads to a more effective and reliable market in terms of daily operations.

COMMISSIONER KELLY: Thank you. One of the points you mentioned in your answer to me is something that I know this Commission has been concerned about and I hope and believe that we will spend some time thinking about -- that is, why investment in transmission has been lacking and what should be done to spur that investment in an appropriate way and in particular what FERC can do to push that process along.

CHAIRMAN WOOD: I thank you all. Alison's presentation was really the predicate for what we've been looking forward to the report getting out, before we actually took our first, but not last series of public steps to address, not only the blackout, but the broader concerns that the report looked at.

I do note in the report, as Alison pointed out, that there are some 46 recommendations. A number of them apply directly to us. We will be talking about that in our next item.

There are a number of others that have overlap with what FERC does, but are primarily centered either at NERC or with industry. Our next item does not actually speak to that today, but they are items, that, again, I recommend the 46 items which are in the report here back about Chapter 10, I believe. They're thoughtfully written and quite readable.

I would recommend that we do that. The recommendations of the task force led to our desire as an Agency to put out our initial response to the report and what the issues are that related to us. I'd like now to ask Bill Longnecker, Jonathan First, and Christie Walsh to discuss two items, E-6 and E-7, which relate to a policy statement from the FERC on reliability issues, also a specific data request that relates to vegetation management, which, as you know, is identified as a significant initiating and contributing factor to the blackout of last summer.

MR. LONGNECKER: Good morning. Item E-6 is a proposed policy statement that addresses a number of issues that relate to the Commission's role and policies regarding the reliability of the nation's interstate bulk power systems.

Item E-7 is a proposed Order that directs all entities that own, control, or operate certain designated transmission facilities in the contiguous 48 states, whether or not they are otherwise subject to the Commission's jurisdiction as a public utility, to report on the vegetation management practices they use for the designated transmission facilities and associated rights of way.

For E-6, the policy statement, as noted, is a response to various recommendations in the April 5th Final Blackout Report. The policy statement is also a response to the written comments submitted after the Commission's December 1, 2003 public conference on what actions the Commission should undertake to promote reliable transmission service and interstate commerce.

In the policy statement, the Commission supports NERC and industry efforts to translate the existing reliability standards into clear, enforceable standards by early 2005, and the need for public utility compliance with industry reliability standards.

In addition, the Commission assures public utilities that it will approve applications to recover prudently-incurred reliability-related costs. The Commission recognizes that many aspects of system reliability are within the purview of the states.

The Commission intends to work closely with the states to address matters of mutual concern. The Commission will also work with the states and NERC to remedy any deficiencies in public utility implementation of reliability requirements and cooperate with Canada and Mexico regarding reliability issues as well.

Some of the other matters that are addressed: The Commission confirms its continued consideration of reliability implications in Commission decisionmaking and any authorization of a new ISO or RTO to become operational.

The Commission clarifies that the term, "good utility practice," used in the pro forma open access transmission tariff, includes compliance with NERC reliability standards or Regional Reliability Council standards that are no less stringent than NERC standards, and will consider, on a case-by-case basis, proposal to amend the tariff to address limitations on reliability in connection with the standard for reliability and the types of damages for which the public utility might be liable.

The Commission also supports variations in standards for the transmission provider or other relevant entity that can demonstrate that regional reliability standards account for physical differences in bulk power systems and are no less stringent than and are not inconsistent with NERC's reliability standards.

The Commission will also address potential mechanisms for funding NERC and the Regional Reliability Councils in cooperation with Canada to ensure their independence, and should energy legislation be passed, the Electricity Reliability Organization.

Item E-7, the Vegetation Management Reporting Order: As noted, this Vegetation Reporting Order is also driven by the findings of the Joint Task Force on the Blackout Report.

That Report noted that the failure to adequately maintain vegetation within transmission line rights of way was both a major cause of the August 2003 blackout and a common factor contributing to many previous regional outages.

The Vegetation Reporting Order directs transmission entities to report on their vegetation management practices with respect to certain designated transmission facilities. Each report should describe in detail, the vegetation management practices and standards that the transmission provider uses for control of vegetation near designated transmission lines.

The report should list the designated transmission facilities under the transmission provider's control and indicate how often the transmission provider inspects the facilities for vegetation management purposes and when the most recent survey of the facility was performed.

The report should indicate whether any identified remediation has been completed as of June 14, 2004. Each report should describe any factors that prevent or unduly delay vegetation management.

The designated transmission facilities include transmission lines with a rating of 230 kilovolts or higher, tie line interconnections between control areas or balancing authority areas, regardless of voltage rating, and critical lines as designated by the Regional Reliability Council. Thank you.

CHAIRMAN WOOD: Thank you, Bill. I just want to add one thought on that last Order, the Vegetation Management Order. I had to deal with these issues on the state level in my last job.

I recognize that it's extremely hard to try to standardize any approach towards vegetation management. I want to say that the approach we have taken in this data request is to ask the utility what their standard is, where does it come from. Tell us a what it is and what you are doing to comply with your standard.

This information collection, which is to everybody and not just to the FERC-regulated entities, is in the context of, according to Congress, under the Federal Power Act 311 authority. It is not an attempt to expand over jurisdictional entities we don't regulate; it's an attempt to get a comprehensive picture on what's going on here in the United States part of North America and to allow states and other utilities to know what's going on in a neighboring state and a neighboring utility in a uniform format fashion, so that the information is actually useful to utilities and their customers.

I will also admit, in light of your exhortation, Alison, that there is a bully pulpit out there. I would hope that any utility that has to answer about June 17th about the status of their vegetation management is going to have addressed any open items on their vegetation management punch list by June 16th, before they sign this Order and send it off to us.

I hope and expect that the Scarlet Letter approach that NERC is using in this interim period between now and the time of that formal authority to go to us and the NERC under our statute to do this job more straightforwardly, can use the Scarlet Letter approach successfully to make sure utilities are taking care of their knitting.

I look forward to working with you on the implementation issues on these broad and unusual data requests, but I think the bottom line is that we want to know before we get into the hot summer, that everybody has taken care of tree clearances and done some of the basic jobs of running the utility that sadly were not done last summer.

COMMISSIONER BROWNELL: Alison, do you want to describe the work you've been doing with the special committee formed by NARUC, for which we are very grateful, to deal with this issue? We do understand -- and I think the Order appropriately recognizes the role of the state, but with the leadership of the Commissioners and Judy Rickman and Connie Hughes, we are working hand-in-hand, and you might want to talk about that for a minute.

MS. SILVERSTEIN: My pleasure. As part of the blackout investigation for the Commission, a very specific, focused investigation in to tree-trimming for bulk system reliability, we released that report in March, early March, in time to present that at NARUC. I had the opportunity to share those results with many NARUC committees.

As a result of that, the NARUC Critical Infrastructure Protection Ad Hoc Committee, chaired by Commissioner Hughes of New Jersey, agreed that tree-trimming for transmission lines was a significant priority, and appointed Commissioner Ripley of Indiana to lead a group of state commissioners to work with us on this effort.

They agreed, as a data collection measure, it would be most efficient for us to get the information to share with them on January 18th. We will be taking the full collection of responses we received on this material and sharing it with all the members of the NARUC committees and any other members of the NARUC community who want to join us.

Our goal is to work together. No one knows who's got jurisdiction over this. It doesn't really matter. What matters is that the trees get trimmed. Our goal is to figure out how to do that in the most effective way, and in a way that assures that folks in one state don't get blacked out by someone else's attack trees.

The goal is consistent, effective vegetation management and vegetation policies. Our job is to work together to figure out a way to get that done. Thank you.

COMMISSIONER BROWNELL: Thanks.

COMMISSIONER KELLY: There has been debate about the extent of the Commission's jurisdiction over reliability. I'd just like to underscore that I think that our approach in the policy statement is very clearly within our authority.

There is an open access transmission tariff that exists, a pro forma tariff. In that tariff, the utilities that are subject to it are responsible for complying with reliability, and by our first policy statement here, we make a very strong case that compliance with reliability means compliance with NERC standards.

I'm very pleased that the Commission is taking this step towards enforcing reliability standards.

COMMISSIONER KELLIHER: Mr. Chairman, I just want to make a comment about legislation. One of the chief recommendations of the task force that investigated major regional blackouts recently was that, quote, "reliability standards must be clear, transparent, nondiscriminatory, enforceable, and enforced."

Those words were not in the final report that today, but from the task force, Phil Sharp headed up nearly six years ago. The most important recommendation, the essential recommendation in this report today is exactly the same, that the standards must be enforceable and enforced.

The last three major regional blackouts, July '96, August '96, August 2003, were all caused in large part by violation of reliability standards. We've been taught this lesson three times and we haven't quite learned it yet.

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President Bush recognized the need for enforcement of reliability standards three years ago in the national energy policy. He called on Congress to pass legislation to enforce reliability standards. A few years later, we're still waiting.

The House has passed reliability legislation. It's pending before the Senate, and I urge the Senate, as I have in the past, to pass the pending energy legislation.

I think that if they prove unequal to the task, they will have done a great disservice to the American people. Phil Sharp's task force also made a host of recommendations. Very few of them were implemented.

It's frankly remarkable to me, how little progress we've made toward improved reliability in the past six years or going back to '96, eight years.

I just want to commend Chairman Wood for acting so quickly in the wake of the final report being issued, to adopt the recommendations, and that the Commission's action today stands in contrast with some of the inaction of the past.

I support the Orders and I just wanted to commend the Chairman.

CHAIRMAN WOOD: I wanted to say that you guys have been kind of in the batter's box since the December 1st conference when we were trying to assess whether there's an appropriate step to take.

Clearly, the ideal steps to take are not the ones that we can actually do today. Joe laid down a good predicate. All I can say to that is amen, but we can take steps, and this is, again, the first.

As we'll talk about after this Order, in looking at institutionalizing this, as Congress and the President gave us the appropriation to do, this won't be just a passing out among our agenda; it will be an institutional part of our Agency. We're here to stay on this issue. I appreciate your candor on the frustration of having been here before, which has not only shown up in some of your public statements, but in the task force's report, there is a whole chapter about having been here before.

Chapter 7, read it, memorize it, 1965 to today, seven items that appear in each blackout report -- embarrassing.

CHAIRMAN WOOD: Let's get going on our first steps publicly of trying to turn the ship around here on reliability. Let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye on both items. Thank you. Now, to close out the suite of reliability initiatives, I'm going to ask Alison to come back to the microphone and talk about the reliability team.

MS. SILVERSTEIN: Can we have the next PowerPoint, please?

(Slide.)

MS. SILVERSTEIN: Congress was good enough to give us $5 million for fiscal year 2004 to do something to improve electric reliability. We have in response, formed up a new division under Dan Larcamp and OMTR. We started staffing it, you all reviewed and approved a work plan in January, thank you very much.

We started staffing in January and, to date, we have 15 staffers whom I will introduce in a couple of minutes. Slide 2, please.

(Slide.)

MS. SILVERSTEIN: The purpose is fourfold: To improve bulk grid reliability for this coming summer; to improve system reliability for the long term; critically, for the work of this Agency, to assure that reliability complements and improves markets and vice versa; and, last, to learn from past reliability failures and not keep making the same mistakes over and over again. Next, please.

(Slide.)

MS. SILVERSTEIN: We have a number of short-term priorities. The first and probably most unrecognized within the public is the participation in the NERC's reliability readiness audit.

As I mentioned, as to our staff, we have nine people supporting this effort, all professional engineers, and, effective yesterday, there will be ten. We will have, as I said, two people participating on every one of these audits. NERC committed to do at least 20 between February and June 30, covering 80 percent of the United States' load.

We are working with NERC to improve the reliability standards, scope, clarity, measure-ability and enforceability. As you have heard, ad nauseam now, our participation in the binational blackout investigation, which I hope is now almost over -- There is ongoing work incorporating reliability considerations into rules and cases in the policy statement that you have just adopted.

We'll increase our efforts in terms of how to better integrate reliability. We have to spend some time thinking about what a reliability impact statement means, so it's going to be a lot of work for OMTR, OGC, and others to figure out.

Another short-term priority is building staff for the new group. Next slide, please.

(Slide.)

MS. SILVERSTEIN: Long-term priorities are to build and excellent staff. Of course, we're starting with an excellent foundation to build the long-term capabilities of the team and the Agency as a whole, to support the reliability mission.

Next will be building federal/state partnerships for reliability regulation and promotion on issues like vegetation management; building a partnership with Canada, NERC, and the industry to assure strong, consistent, binational reliability rules and implementation, so that our grid and Canada's, which are interconnected, are being run according to the same rules and principles, and, most broadly, improve bulk grid reliability and security. Here, I'm distinguishing between reliability, that is, to keep the lights on, as is, of course, with normal operation, and security as in the protective, preventive sense. Next slide, please.

(Slide.)

MS. SILVERSTEIN: We have a number of specific initiatives going on. I list a few.

First is the reliability readiness audits. A second important one is the First Energy reliability study that follows on the Order you all issued December 24th. Said Farrakhpay is our lead on that as a member of the expert team working with First Energy to review the study, identify the details of the vulnerabilities, and to develop a set of recommendations for what needs to be done to improve those.

MS. SILVERSTEIN: -- Learning from the blackout. As I mentioned earlier, we were working DOE, Canada, and NERC to develop a conference in May with the industry to develop reliability standards and schedules -- also, as I noted, working with NERC for reliability standards revision and compliance templates.

Mike Oliver is already doing work on this. His work is now being supplemented by folks who are members of the different NERC committees, including operations, planning, and markets, and working with the Nuclear Regulatory Commission on grid reliability and nuclear plant needs, continuing the discussions you all started with them a few months ago.

Leads on that are Bruce Poole and John Kueck.

Next slide, please.

MS. SILVERSTEIN: We have a number of R&D initiatives that are under way. The Chairman made the call and you all supported it. But it was important to invest not just in the short term but in some long-term leadership and understanding of reliability issues.

Some of the things we have already spent the taxpayers' money on and are planning to use this money for, including the transmission vegetation management study released in March. Saeed Farrakhpay and Gary Nakareda were important in that study.

We have a study under way to look at replacement transformers and what it would cost to get more of those on U.S. soil. In the same way that you have a spare tire in the trunk of your care in case of an emergency, you probably need a heck of a lot more transformers to bolster the grid. Paul Robb is our lead on that.

We're looking importantly in understanding technology risk and prudence because one of the most important problems limiting the adoption and investment in new technology across the grid today is that regulators and managers want to play "got ya" and people don't invest because they all want to be the second or third to adopt a new technology.

So you we need to better understand and give some kind of safe harbor guidelines for what are the technology risks and how do we tell if this new technology is a prudent investment or not.

Tom King, who is one of our contractors from the Oak Ridge National Labs, is our lead on that effort. The state of cyber security is a contract that's going to be going under way any minute now I hope.

We've been working for the past year with a natural gas pipeline industry on the impacts of gas pipeline disruption in terms of major scale deliverability reductions on a region.

This is important to electricity because at least 24 percent of the United States' electric generation in terms of megawatt hours is generated from natural gas use.

So we need to better understand gas pipeline disruption impacts on the consequences for electric reliability. This is relevant even for peak days apart from the potential gas pipeline attack. Training is something that I all know you all are interested in. We are saving some of the R&D money to use with NERC and the industry to figure out the kind of longterm training needs assessment that is required and recommended in the blackout studies.

And one of the last things we are looking at and shaping up right now is a study of the Lake Erie loop and the parallel flows that occurred there. It is not merely a physics problem. It's also an economics problem.

We need to understand both. We will probably do this in house. This is a long term project for the reliability staff.

Last, I would like to introduce members of the reliability team if I may.

(Slide.)

MS. SILVERSTEIN: Rather than read everybody's name I'm going to ask all you guys to stand up. But they are here. These include 15 people who are both contractors.

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Oh, what the heck. We will read the names. Michelle Brookson there someplace, Saeed Farrakhpay, Cliff Franklin, Don King, Tom Wong, Richard Mayberry, Cynthia Pointer, Bruce Poole, and Paul Robb are all full-time FERC staffers.

Two of them, Richard and Cynthia, are out on reliability readiness reviews today, which is probably a really good use of their time.

Then we have been lucky enough to find some superb contractors to work and bring a good expertise to us. Those include Tom King, Brandon Kirby, and John Kueck. Apparently Oak Ridge National Labs only hire people whose names start with K.

Frank Macedo and Chris Mack are our Canadian imports. I think Canada has last names which start with other letters. And Gary Nakarda, whom we've been lucky to borrow from the National Renewable Energy Lab.

Thank you all for coming. Kevin Kelly and I and Dan Larcamp have the great pleasure of working with these folks. Thank you all very much.

We also have a brain fest of people outside the reliability division whom we are able to call on -- and do at regular intervals. They include Mike Oliver, Bill Longenecker, Sarah McKinley, and Jonathan First.

I am sure others in this building will get called on for help because of their expertise as well. Thank you very much.

CHAIRMAN WOOD: I appreciate you all being here today. But more importantly I appreciate -- as I did two years, Mr. Hederman, when we set up your shop -- both the challenge and the excitement as well as the anxiety of being members of a new division.

I hope you all have heard from our comments today that this one's here to stay too. Just like market oversight, it's an important part of our charge for the American people.

I appreciate you all, both the folks that are here already, plus the folks that have come with us from the outside to lend your expertise and gifts to us to help build and create this group for the long term.

I have to say after nine years of working with you, Ms. Alison, I appreciate the context of what you talked about here today, both on the report and in helping set up this group.

Someone with your experience, your tenacity, your hustle, your analytical chops -- as one who's been on the receiving end of it too -- you're a tart- tongued task mistress.

(Laughter.)

CHAIRMAN WOOD: I think you have a nice ability to really corral a lot of folks here externally and internally, to do some real good service to the country, and develop some good, good policy. And that's what we're all about here: tell the truth and do the right thing.

When the going gets tough, I can't think of anyone else I'd rather share a foxhole with than you. So thanks.

MS. SILVERSTEIN: Thank you.

(Applause.)

COMMISSIONER BROWNELL: I just have a couple of questions. You're talking about burning from the blackout. How are we involving the coops and the public power folks in this discussion so that they are an active part of what we develop and feel good in -- close partners in this?

MS. SILVERSTEIN: I don't have an answer to that yet because we are not the leads on developing this conference. So I'm waiting for the energy organizations of two countries to get things organized so they can go on do it.

But I assure you they are members of the industry and they will be invited. To the degree that we have some influence on the agenda they'll have a part to play.

COMMISSIONER BROWNELL: Maybe as an ongoing part of the team development we want to be sure maybe to go and meet with the associations in which they are involved.

Tell me what the economic problem on the Lake Erie loop is. You said there are several problems. What is the economic problem?

MS. SILVERSTEIN: The great thing about parallel flows is that electricity goes where it wants to go across the transmission lines, no matter who owns them and no matter what's scheduled.

The reason it's called the Lake Erie loop is because there just happens to be this body of water in the middle and a whole bunch of lines going around it. So the electricity, unless you put some significant chunks of hardware to control the flows, the electricity -- as Canada has done some of them, and ITC is threatening to do more of it -- the electricity goes where it wants to go.

And people -- some people make money off where the electricity goes and some people lose money off where the electricity goes. But the electricity keeps going there.

The Lake Erie loop is frankly one of the reasons why it's a good deal for AEP and Con Ed to be part of PJM. So the question is, to better understand, who is it who is making money and who is it who's losing money?

The economists all search to identify and nail done the cost of externalities and better understand the public goods to make sure that the people who are causing the costs pay for them.

In the case of parallel flows I don't know if we could figure all that out, but we need to understand it better. And we also need to understand it better because, as in the case of the blackout, this blackout -- it may not cause a gross reliability problem, but it certainly causes significant engineering and flow management problems.

And we need to have a better understanding of what those are in order to develop a more effective set of hardware and grid management capabilities to both manage the flows more effectively and better match the beneficiaries with the recipients and the payers.

COMMISSIONER BROWNELL: Thank you. Let me point out that's okay to make money as long as they do so legally and add value to the customers.

I don't think ITC's are threatening to invest. I actually think we've seen some investment. I'm teasing. --

MS. SILVERSTEIN: What I was referring to was a very specific proposal by the ITC and a very specific hardware.

COMMISSIONER BROWNELL: This is going to be your baby. What's your vision?

MR. LARCAMP: I'm going to become a card carrying member of the reliability team once I learn how to do the clapper system in my office to keep the lights on there.

(Laughter.)

MR. LARCAMP: The process sometimes is frustratingly slow, but yesterday afternoon I received an informal package of the rankings of the people that applied for the director position. My expectation is that later this week we will start scheduling interviews for the top people on the list.

It would be my expectation, when those people are in, that I would want them to meet with all of you to have discussions so that we can collectively make judgments about who is the best person out there to lead this new group.

We will also be moving forward fairly quickly on advertisements for some of the SL positions that Congress was good enough to give us to staff the new organization.

A lot of work to do. I think one of the most beneficial things, I think, is the opportunity this has given the people that are already in our organization to basically showcase their talents more extensively in their area of expertise inside the building, but also outside the building.

We've gotten excellent reports on their contributions to the audit teams to date informally. And we expect that they will basically provide a strong nucleus with hiring from the outside to make sure the Commission is prepared to do what we need to do with or without -- hopefully with -- legislation as we move forward in trying to provide the appropriate incentives and oversights to insure that reliability is all that it can be.

COMMISSIONER BROWNELL: Thank you.

COMMISSIONER KELLIHER: I just have one question. You discussed how the FERC reliability team would participate in readiness audits, but no discussion on compliance audits. Will the reliability team participate in future compliance audits?

MS. SILVERSTEIN: That remains to be seen and it is not clear whether it is a FERC decision. At present reliability readiness audits are conducted by the NERC with volunteers from across the industry. So we are participating in those as volunteers on the same ground and terms as members of the industry.

The compliance audits, in contrast, have traditionally been conducted by the regional reliability council. And they include only members of the regional reliability council area. So both staff from the reliability council and folks who work for the utilities that are their neighbors -- there may or may not be NERC representatives, but usually not.

It remains to be seen how the industry will choose to change their reliability councils and how the compliance auditing process will change and whether that will go more into the NERC mold.

It is clear if you look at it from a strict governance and independence point of view that you will get a far better quality audit if you do not use folks who are neighbors and who have a consistent regional-based interpretation of the terms of the audit.

But it remains to be seen both for the reliability councils and for the new NERC standards for audit purposes whether they choose to invite us to participate in those as well. I think that's an issue to be developed.

COMMISSIONER KELLIHER: If legislation is enacted and an ERO is certified, would the ERO perform compliance audits?

MS. SILVERSTEIN: I can't answer that. I personally believe it would be appropriate, but it's not my judgment to make.

CHAIRMAN WOOD: I think the language of the proposed statute, if it's going to be the one enacted, clearly would allow the Commission to be either doing its own independent side of the enforceability of those rules or participate as a team in my review of that as we were just kind of white-papering this concept back in December -- or white-wording this concept.

That was clearly what was planned in the budget. There would be the ability for us to in fact do either a team audit approach on compliance with the rules or do it independently depending on what the statute provides.

COMMISSIONER KELLIHER: It would just seem once the legislation is enacted, the ERO would presumably do compliance audits to assure that the standards they've developed and we've adopted are actually honored.

There may be a question on whether we would participate. But it would seem to me that the ERO would have to do compliance audits if the legislation is enacted.

CHAIRMAN WOOD: I think that's a big part of what they will do and actually a big part of what the reliability team will do independently, depending on how the ERO stands up to it.

MS. SILVERSTEIN: It is my observation that the team of staff that we have now with the training they are developing and the skills that they are going to bring to the reliability readiness review will be more than capable of stepping into a compliance audit process.

I suspect that if you all volunteer then to participate that their participation would be welcomed by all those who want a reliable system and a truly independent audit process.

COMMISSIONER BROWNELL: It seems to me -- and

I've said this often -- that we might want to look at the banking system for an audit process at work. We have financial rules. There are rules, by the way, so you can actually do audits rather than reviews.

They had experts both at a national and a regional level who understand the nuances. But they are independent on the industry.

And it works. People understand the rules. They all feel that they are very productive audits because you learn a lot about your own organization and you improve.

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COMMISSIONER KELLIHER: Thank you all very much.

SECRETARY SELAS: Mr. Chairman, as the next item of the discussion agenda we will take up number E-53. This is Michael J. Chesser, a presentation by Melissa Mitchell, accompanied by Jim Akers, Thomas Mey, Larry Greenfield, and Jamie Simler.

MR. MITCHELL: Good morning, Mr. Chairman and Commissioners. Item E-53 is a draft order that denies authorization for Michael J. Chesser to hold interlocking positions as chairman of the board of Kansas City Power and Light, a public utility, and a director of Itron Incorporated, an electrical equipment supplier.

The Federal Power Act prohibits persons from concurrently holding positions as an officer or a director of a public utility at a company supplying electrical equipment to that public utility unless it is found that neither public nor private interests will be adversely affected. He should not be in a position where the supplier is in the position to have furnished an appreciable amount of electrical equipment to the utility. --

This draft order finds that the level of purchases by KCP from Itron are not diminus, especially as soon as anticipated purchases are made from Itron.

Therefore the draft order finds that, given the size of potential business, as well as the senior management position that he holds, he has not met the burden of demonstrating that the interlock will not adversely affect public or private interests.

COMMISSIONER KELLIHER: Mr. Chairman, I just want to thank you for calling this order as a discussion item. As the staff indicated, Mr. Chesser holds positions on interlocking directorates without prior Commission approval, a clear violation of section 305 (b) of the Federal Power Act.

He assumed the position on October 1, I believe, and waited three months to seek approval. So he did seek approval eventually, but three months after he assumed the position.

I think it's appropriate that the order denies authorization. But I am concerned about the violation. And I'd like the general counsel's office -- I think they are exploring what kind of penalty might be imposed upon someone who does engage in this kind of violation.

In my personal view I think someone who assumes an interlocking directorate position without Commission approval should forfeit the compensation that he gained during the period of unlawful service. I don't know if they have the authority to do that. But to me that seems equitable.

MS. MARLETTE: We have not, to my knowledge ever assessed a penalty for violating this provision. Right now we have some attorneys in our solicitor's office looking at whether the Commission could, if it wanted to, require the scorchment of the fees required that were received along the lines of requiring discorchment of profits for utilities who violated the tariff.

Right now I don't have a clear answer for you. I think we are not going to find an absolute yes or no. It's something the Commission could possibly consider.

COMMISSIONER KELLIHER: I'm also concerned that he may not be alone. I'd like to ask the staff whether they have any reason to believe that he is unique in this respect. That he is the only person serving in interlocking positions without Commission's approval.

MR. MEY: Most of the problems we see is always the person who is director of the utility with maybe a very small, maybe $20,000 or $50,000 a year electrical equipment business. So it is very diminimis.

I think most of the Directors know the requirement. We get many inquiries from attorneys on the interpretations so I don't think it's unknown. I can't say whether there are people out there who are doing it without our knowledge.

COMMISSIONER KELLIHER: Is it the norm for people to seek prior approval before assuming a position?

MR. AKERS: Once in a while someone forgets it for a couple of months and they come in later but there is not a whole lot of these applications filed on this type of electrical equipment.

You might have two or three a year if that and most of those come in prior to the time they are on board.

MR. KELLIER: Unless we are confident that he is fairly unique. If we do thing there are some reasonable grounds to think there are other people serving in interlocking positions without authorization, I hope we can look into it.

In the meantime, I would encourage any person serving in interlocking positions without authorization, to seek it.

CHAIRMAN WOOD: We'll act quickly.

COMMISSIONER KELLY: I would like add that the law is very clear that this prohibition applies to the individual who seeks to become a member of the Utility Board. But I have a problem with the fact that Kansas City Power and Light made the offer to this individual and sat this individual on the Board.

I personally hold the utility responsible. I believe that knowing the Federal Power Act, the utility should undertake due diligence to ensure that no potential member of the Board is offered a position with the Board unless there is no conflict of interest. This is a duty that the utility owes not only to its consumers but also to its shareholders.

I'd like to ask the Office of General Counsel to look into the legal authority that we have to hold the utility responsible for this kind of behavior.

MS. MARLETTE: We will do that.

COMMISSIONER KELLY: Thank you.

COMMISSIONER BROWNELL: At the very least and I can't speak to an individual case. I'll suspect this is not unique. I also know that we have had applications that sat around here for a while. I think it would behoove us perhaps to do an advisory letter to the CEO through the General Counsel, advising them of their responsibilities because it is in fact their responsibility.

When you serve on a bank board, you sit down with the General Counsel and/or the CEO and go through very clearly, and I've invited them to talk to the regulator directly.

It's a very clear, pretty comprehensive list of obligations that you have. I agree with you, this is the obligation of the General Counsel or the CEO or to police the institution. I think that would be the direct course of action rather than trying to investigate to put people on notice very quickly and frankly to advise people considering service on Boards, that they do some due diligence on that.

It's very difficult to know, and another industry perhaps exactly what the expectations are.

CHAIRMAN WOOD: Thank you for bringing it up. Let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is M-1 the standards of conduct for transmission providers. Preceded by Ms. Anas, accompanied by Ellen Schall (inaudible). William Longnecker and Jilian Lake.

MS. ANAS: Good morning. Before there was a draft order of a hearing in 2004 (*). The draft order denies rehearing in part and provides clarification. Before I touch base on the specific point in the draft order, I would like to thank, in addition to the team here, a number of people who have helped us out a bit on specific research issues or reviewing documents, which were voluminous in this proceeding

They include Tom Bromfield, Tom Alverez, Roland Schicar, Kim Vanderize, James Campbell and Thomas Donald from OMTR, Larry Honagami, Stewart Fisher, Shirley Ganalis and Megan Sterling from OMOI (*).

Specifically the order on rehearing qualifies the definition of energy affiliate. It also qualifies for the first time the definition of marketing affiliate in response to requests from petitioners.

The draft order clarifies which maintenance of employees of transmission providers may share with energy affiliates. It also clarifies that a transmission may share with its energy affiliates, information necessary to maintain the operations of the transmission system. It codifies the exception that permits a transmission provider to share senior officers and directors with its marketing and energy affiliates, as well as codifying the exception that permits that transmission provider to share its risk management function with its marketing and energy affiliates.

We also codify that a transmission provider may share information for corporate governance purposes with its marketing and energy affiliates.

Finally, we grant rehearing and defer the implementation date to September 1, 2004.

CHAIRMAN WOOD: Who is first?

COMMISSIONER KELLY: Thanks Demi, thanks to your entire team. I know, this has been a long effort and I'm very pleased with the outcome. As a new member of the

Commission, I joined the Commission after the final rule was issued in order to be able to participate in this request for rehearing. It's taken a lot of work on my part and the part of my staff to understand the history leading to this rule and to get a grasp of the approach that we've taken.

I am satisfied that the approach that the Chairman and Commissioner Brownell initiated in coming to this rule is an excellent one. I think the key goals of this rule to prevent preferential access to a monopoly service and to prevent preferential sharing of information to an affiliate, are worthy and appropriate goals. I applaud the two Commissioners to my right for taking action on this. I know it's been a big effort.

There have been numerous comments, about a hundred interested parties who have requested rehearing. Many commenters have urged the Commission to apply the standard of conduct to all the affiliates.

Commenters have also express concern that the regulated entities, the transmission providers without this rule can transfer benefits from the monopolies to their unregulated affiliates, which could then use that preferential access or information to reap the competitive advantage in other markets. I think the matter is inappropriate and I believe the steps that the rule takes to ensure that that doesn't occur are good works.

In our order on rehearing, we have fine-tuned the rules in large part to ensure that we are not creating a solution where a problem didn't exist.

For example, the rule now excludes small pipelines. It also generically exempts from the definition of transmission provider, natural gas storage providers authorized to charged market based rates that are not interconnected with the (*) facilities of any affiliated interstate natural gas pipeline, have no exclusive franchise area, no captive customers and no market power.

I think that's an excellent change. The rule also clarifies that an LDC buying or selling a deminimis amount of gas to enable it to stay in balance under its transportation balance will remain exempt from the energy affiliates status, which I also think is an excellent outcome.

Some commenters express concern about the rules impact on t he safe and reliable operation of the grid. In response, the Commission in its order on rehearing has clarified that the permitted sharing of "crucial operating information" is not limited to emergency information but instead is information necessary to operate and maintain the transmission system on a day-to-day basis.

I think that is an excellent clarification. It shows the Commission intends that transmission providers can share information such as conformations, nominations and schedules with upstream producers and gathering facilities. Operation data relating to connection points and communications relating to the maintenance of interconnecting facilities.

Along similar lines, the Commission has also clarifies that the exception that allows for the sharing of field and maintenance employees also covers technicians, mechanics and their immediate supervisor.

As I said, it was not the Commission's intent to create a solution where a problem doesn't exist. I'd also like to make one last point. There is no prohibition in this rule. A transmission provider doing business with an affiliate, what this rule is aimed at is ensuring that those business relationships are carried out in a way that does not give the affiliate an advantage in a competitive market that other people don't have.

So thank you for your excellent work, I appreciate it.

COMMISSIONER BROWNELL: I'm pleased that we extended the timeline for implementation and that we get some clarity to who gets named and how. I think this is an order of sizement proportions for those who have to live with it.

I actually think it helps the industry because it gives them guidance but more importantly, had there been clearer sets of rules, about affiliate relationships going into the market meltdown and the chaos we've seen in the lat couple of years, I think there would have been better accountability and more credibility for the industry itself and I think the industry has recognized that and made some really substantive and positive recommendations, many of which we have adopted.

I do, however, think that as clear as we are, that we often think we are a whole lot clearer than anybody else thinks we are. We need to make ourselves, the staff particularly very available to the industry for points of clarification.

I heard some concerns that we had communicated, we wouldn't be issuing advisories as we did in some of the transmission orders after the gas industry. I hope that's an incorrect perception of what our willingness to do is.

I think people want to do the right thing. Sometimes when you get into the very details of how these businesses are run, it's very hard to figure that out. I think we have an ongoing responsibility to work collaboratively to make sure that the interpretation and training that's been developed and having somebody in to talk about some of the training, the web-based training they've developed is correct.

This isn't just about going out to get people. This is about making sure the competitive markets work and are fair. I think we as industry leaders recognize that so I appreciate that. I am concurring in part as a continuation of my previous concurrence. We've made some movements. I would have done a little more, no big deal, on a very small aspect of this. All and all I think you have done a terrific job and I think the comments, sometimes we get comments that you wonder why people bother to waste the paper.

These comments have been very, very substantive and helpful in developing a better understanding of how businesses are run and what individual companies have in terms of structural issues. Good job I think.

COMMISSIONER KELLIHER: I'm going to vote for the rehearing order but I do so with some discomfort because I think what we are doing here is improving a rule that is flawed. In my view the flaw and the standard of conduct final rule and the lack of any record evidence suggesting that this rule should be expanded beyond marketing affiliates.

The basis for the rule, for expanding the scope for the standard of conduct, is the observation that "changes occur in the electricity and gas industries when the standards of conduct refers to (*). I certainly agree with that and if there has been a proliferation of energy affiliates, I agree with that as well.

But also a suspicion that affiliate abuse is occurring in the dealings between transmission providers and energy affiliates.

In my view, suspicion that that kind of activity is occurring is not a sufficient basis for expanding the scope of standards of conduct beyond market affiliates.

The final rule and the rehearing order cited a number of instances where affiliate abuse has occurred. The cases cited by the orders all relate dealings between transmission providers and marketing affiliates, not other energy affiliates.

There is no factual basis that I can see to support expanding the scope of the rule beyond marketing affiliates.

With respect to some of the discrete policy calls made in the rehearing order, I largely agree with them. I would have gone further in some areas to limit application of standards of conduct, in particular, I would have granted the exemption to local distribution companies that make no sales to affiliated pipelines and also granted an exemption to Part 157 pipelines.

I also would have granted the rehearing request by Williams to clarify the role of senior officers and directors in managing the companies. In the final rule, corporate officers who participate in decisions regarding transmission investments would be considered employees of a transmission provider.

At least that's my understanding of the rule. Currently, decisions on large investments are often reserved to senior corporate officers. The final rule forces these officers to make a Hobson's Choice. Either they continue to make decisions on large investments such as a multi-billion Alaska natural gas pipeline and thereby become construed as employees of a transmission provider with all the resulting implementations of the information sharing, or they divest themselves of responsibility for making decisions on the investments.

To me it seems inconsistent of the corporate governance provisions of the of the Sarbanes-Oxley Act. I don't think in letter, but in spirit. Two years ago, the DC Circuit overturned the Commission order that extended the standard of conduct rule beyond marketing affiliates.

In the Dominion case, one reason the Court cited was, that they felt that the Commission's order would "destroy corporate deficiencies without justification." And I have some of the same concerns about the final rule. I do support the rehearing order though and I do appreciate all your hard work on the rehearing order.

LAUGHTER.

COMMISSIONER KELLIHER: Thank you.

CHAIRMAN WOOD: I do want to say as to the Sarbanes-Oxley issue. Joe, you raised in paragraph 138 or so, of the new draft. I think --

COMMISSIONER KELLIHER: I think it's consistent with the letter of the law. As I understand Sarbanes-Oxley, it's requiring that corporate officers be informed of things happening in the company but the issue here seems to be, can they make decisions. I think the final rule as provided by the rehearing order is concerned with my primitive understanding of Sarbanes-Oxley because once they step out of the decision-making role on major investments, they can be informed about the decisions made by lower-ranking employees in that company.

MS. ANAS: Can I provide a little insight into that? The staff actually met with the SEC concerning Sarbanes-Oxley implementation and had some long discussions with them about our rules vis- -vis Sarbanes-Oxkey, which of course came after the NOPR but before the final rule.

Very high level officers, the CEO the CFO, general counsel, other types of employees would not be considered operating employees and are not treated as operating employees and can be shared. The circumstances at Williams are very unique because their senior officers, at least in their pleading, they describe as being operating employees. So not only are they involved in the high level decisions, but they are also involved in the more day-to-day decisions of their respective divisions.

And so, for example, the President of the division responsible for marketing would have dual roles and the sharing of operating employees is something that we have found inconsistent with the independent function requirements for some years.

COMMISSIONER KELLY: I'd like to respond to something that Joe said. Joe's concern about the facts of abuse or lack of facts of abuse in the record, particularly, I think, in the gas industry, was something that initially took my attention when I looked at this record and pondered the request for rehearing.

My thinking on this has evolved. At this point, the way that I look at it is, what we are doing here is, we are implementing standards of conduct. The purpose of them is to prevent abuse from occurring.

We don't need to have cases of abuse to happen before we implement a code of conduct, if you will, just like we don't need to have another blackout to implement standards of conduct for reliability, broader than in the areas where we've seen past abuse.

This is a code of conduct and because the type of code of conduct that we put in place or the type of standards that we put in place, are very reasonable, and are really an expansion of what was done for marketing affiliates. I think that our approach is a reasonable one. It's certainly not arbitrary.

I think it's a good decision to put these standards of conduct in place before we see cases of abuse. I think, as I said, that the standards of not sharing preferentially, access to an essential facility and not sharing valuable information with an affiliate that would give the affiliate an opportunity to have a competitive advantage over other persons in the industry, are reasonable responses and reasonable codes of conduct.

CHAIRMAN WOOD: Stay on that. I appreciate everybody's contribution. I think this worked out very good over the last week, that we all focused on it. Everyone came at it from different directions, every single one of us did, actually, so it's an extra tip of the hat to you, Ms. Anas.

(Laughter.)

CHAIRMAN WOOD: For herding these cats up here, thank you for that. I know we will get some requests for individual company exemptions, which we invited in the original rule, and I think that's a prudent way to go at these things.

I think that without question, the downside of any rule of generic applicability is that it may not fit everybody. We've got to have some ability to accommodate those concerns.

I think what was put out in this rule will either remove some of those just completely, or give a lot of guidance as to how our concerns can be addressed in consonance with the business structure.

We'll see some of those. I do know that I think we agreed on a May 10th workshop day down in Houston. I know that the two of you, Sudeen and Nora, won't be able to go. I've got a prior commitment, and, Joe, you indicated that you do, too, but the workshop there is not kind of a typical program, but one that focuses more on what are individual companies doing, what are the best practices that different companies can learn from each other, with us being there as observers and occasional participants.

But it sounds like a great format. I tip my hat to Nora for providing the leadership on that, based on your prior experience in the banking industry about how important it is to get out there and develop our standards and talk about what we want to do is to comply, not catch them with litigated cases, as we've had to do here, but make sure they comply in the first place, so that people trust these markets.

COMMISSIONER BROWNELL: Towards that end, I would hope that the companies will get to us, as many questions as they have about this rule and implementation issues, so it really can be a roll-up-your-sleeves, working, what did you mean by, what are you thinking of, how does this work, can you help me here?

So I really do hope it's interactive, and I give all the credit to the compliance officers of about three trading floors that I visited when I said, are you talking to each other, and they said, no, but we'd love to. The idea was their's and all I did was kind of make it happen.

CHAIRMAN WOOD: You listen, which is a key trait. Sudeen, let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye, noting my dissent, in part.

COMMISSIONER KELLIHER: Aye, noting my dissent, in part.

CHAIRMAN WOOD: I vote aye. Thank you all.

SECRETARY SALAS: The next item in the discussion agenda is a joint presentation. We will take up together, E-1, which is AEP Power Marketing, and E-2, Market Based Rates for Public Utilities. This is a presentation by the Staff, Jerry Pederson, accompanied by David Perlman, Clifford Franklin, David Hunger, Partha Malvaska, and Steve Rodgers.

Let me note for the record that as required by law, Commissioner Kelly is recused from participating in this case.

MR. PEDERSON: Mr. Chairman, Commissioners, it's been some time since we've discussed the supply margin assessment across this table, but I think the time has been well spent. Subsequent to the issuance of the SMA Order, the Commission implemented a comprehensive process to provide an opportunity for all interested persons to submit comments and to provide input as to the possible modifications of the SMA and related litigation.

Going all the way back to August of 2002, the Commission issued a Notice establishing the proceeding in Docket Number PL02-8, to give all interested persons an opportunity to submit written comments regarding the SMA related to mitigation measures.

Numerous entities submitted comments. The Commission then issued a Notice of Technical Conference that included a staff paper that identified possible modifications or alternatives.

We invited all interested person to submit written comments on the Staff paper. Many persons filed such comments. We heard from representatives throughout the industry at the technical conference held at the FERC offices on January 13th and 14th, 2004.

After that technical conference, we provided an opportunity for all interested persons to file supplemental comments. Many more comments were received. To date, the Commission has provided multiple rounds of notice and opportunity for all interested persons to file comments in these proceedings.

We have heard and considered many approaches for determining whether an applicant has market power in generation, and, if so, what is the appropriate mitigation? The draft Order in E-1 concludes that an approach which balances regulatory certainty with appropriate flexibility for those seeking to obtain or retain market-based rate authority, provides all industry participants with a regulatory process that meets our responsibilities under the Federal Power Act, and allows market participants to bring case-specific factors to the Commission's attention in a timely manner.

Accordingly, E-1 adopts the policy that provides applicant with a number of procedural options, several types of generation market power screens, and the option of proposing mitigation to eliminate their ability to exercise market power.

The E-1 Order finds that a single definitive test is not an optimal approach to measuring generation market power. Thus, the draft Order in E-1 adopts two indicative screens for assessing such market power, each with its own specific focus and attributes.

E-1 adopts an uncommitted pivotal supplier analysis based on the control area's annual peak demand and an uncommitted market share analysis applied on a seasonal basis. We will post on FERC's website, examples of these two screens.

The draft Order before you allows for a

reasonable reduction of native load obligations in both the pivotal supplier analysis and market share analysis, as well as reductions of other commitments of the applicant such as planned outages and operating reserves.

In addition, an important factor in determining whether generation market power exists, involves properly accounting for competing supplies.

Under the hub-and-spoke analysis, all competing suppliers and first-tier markets were assumed to be able to be imported into the relevant market. Our assumptions in that regard did not take into account, the physical barriers to moving supplies.

In our Order that replaced the hub-and-spoke with the SMA, total transfer capability, TTC, was adopted as the upper limit for transmission access between control areas, however, numerous commenters have indicated that it is impossible for this amount of generation to be simultaneously imported into an applicant's control area.

Accordingly, after careful consideration, draft Order E-1 replaces the use of TTC with simultaneous import capability as the appropriate measure of the effective transmission notations on how much generation can be imported into a relevant geographic market.

On to the process: If an applicant passes both screens, there will be a rebuttable presumption that the applicant does not possess market power in generation. However, the draft Order allows intervenors to present evidence to rebut the presumption under these circumstances:

For example, intervenors could present evidence, based on historical wholesale sales, and/or challenge our assumption that competing suppliers inside a control area have access to the market. On the other hand, if an applicant fails either screen, this will create a rebuttable presumption that market power exists in generation.

In this instance, the applicant may present evidence to rebut the presumption of market power by submitting a delivered price test, or it may proceed straight to proposed mitigation measures that would eliminate its ability to exercise market power. In all cases, the applicant or intervenors may present evidence such as historical wholesale sales data to support whether the applicant does or does not have market power.

Where appropriate, the screens also allow applicants to submit streamlined applications with respect to mitigation. E-1 addresses the concerns of many commenters by allowing utilities' proposed tailored mitigation to eliminate their ability to exercise market power.

Where an applicant accepts a presumption of market power or the Commission, upon review of delivered price tests, makes a definitive finding that market power exists, then the applicant's market-based rate authority will be revoked, and in geographic areas where market power is found, the applicant will be subject to cost-based default rates or other cost-based rates that the applicant proposes and the Commission accepts.

The draft Order also grants rehearing with respect to the exemption from the generation market power analysis for sales into an ISO or RTO with Commission-approved market monitoring and mitigation, and requires all applicants for market-based rate authority to submit a generation market power analysis.

However, similar to the approach under the hub-and-spoke analysis when performing a generation market power analysis, applicants located in ISOs or RTOs with sufficient market structure and a single energy market, may consider the geographic region under control of the ISO or RTO as the relevant default geographic region for purposes of completing their analysis.

Further, E-1 recognizes the specific concerns expressed by western utilities regarding the appropriate measuring of the capacity of hydroelectric units. Given that hydro facilities are energy-limited units, using nameplate capacity can bias the results of a pivotal spiral market share screen with respect to these facilities.

Applicants are permitted to de-rate their hydro capacity in conducting the two interim generation market power screens, based on historical capacity factors. The draft Order also sets forth numerous ways in which it protects native-load customers.

In closing, I will now address the companion Order, E-2. An analysis of generation market power has for many years been one of the four prongs of analysis the Commission uses to assess whether an applicant should be granted market-based rate authority.

The other three prongs that the Commission considers are whether the applicant has transmission market power, whether the applicant can erect barriers to entry, and whether there are concerns involving the applicant that relate to affiliate abuse and/or reciprocal dealing in E-1 and in prior Orders in the same dockets.

The Commission stated that the generation market power screen that it was adopting in that proceeding was only an interim screen and that the Commission intended to initiate a generic rulemaking proceeding on potential new analytical methods for assessing markets and market power.

The Commission has also stated that as part of this process, it intends to hold a series of outreach meetings with industry experts on these matters. The purpose of E-2 is to initiate a public dialogue with respect to the adequacy of the current, four-pronged analysis and whether and how it should be modified to assure that electric market-based rates are just and reasonable under the Federal Power Act.

In order to better understand the issues that need to be considered in E-2, E-2 states that the Commission intends to convene a series of technical conferences that would be open to the public. The Commission will hold the first technical conference on June 9th, 2004, at the Commission Headquarters.

The purpose of this conference will be to frame these issue that will comprise the rulemaking proceeding, including a discussion of how all four parts of the current test interrelate, as well as what other factors the Commission should consider in granting market-based rate authorizations.

In this regard, Mr. Chairman, Staff recommends that the Commission convene another technical conference in the near future to address affiliate abuse concerns in the context of competitive solicitations of generation and power, which is related to the affiliate abuse portion of the Commission's market-based rate and review. Thank you. Staff is available for questions.

CHAIRMAN WOOD: Thank you, Jerry. Questions? Thoughts?

COMMISSIONER BROWNELL: I'll start. I think that this is a terrific day in the sense that when we issued the initial SMA draft, there was a huge amount of criticism that it was arbitrary, that it was aimed at certain individual companies, that it was unfair, that it was inequitable.

We got a tremendous amount of comments. We had a series of meetings where there were particularly strong and compelling stories, particularly from the coops and the municipal power folks, about the importance of not only dealing with generation market power, but really looking at that four-pronged test.

I think this is responsive to the broad array and often competing concerns that we heard. I think we've got two screens, we've got the delivered price test, we have other optionality, we have extenuating circumstances, so, in effect, I think we are fulfilling our responsibility, which I think some of the critics forgot, which is that we do have market power responsibilities, something that I think we all learned in some pretty painful ways over the past three years.

I am enormously complimentary of the Staff, again, for, I think, being very inclusive, and, frankly, for the dialogue we've just had in the last three days where we tried to be more disciplined and more focused in the way we did it.

My initial concern was that we had bent over so far backwards to accommodate competing concerns and it was so complex, I didn't know how we were ever going to implement it. I think this is clear. I think it is more than fair, but I also think that it can be implemented in a reasonable amount of time, because we've had a lot of things kind of pending out there.

I'm very excited about getting on to the next steps, because the other thing we heard, I think, in strong terms, is that this is one part of the problem, but this is not actually in many cases, the problem. I think a separate conference on the solicitation process is also important, because certainly, increasingly, we've heard and seen some examples where that has caused us to step back and wonder if the native load, whom everyone really wants to protect, is effectively being protected. I think that's an important aspect of it, so I'm happy to support this.

COMMISSIONER BROWNELL: Two things I'd like you to say more about Jerry, or one of your colleagues. Let's talk about the delivered price test because not everyone is familiar with that as perhaps we are and let's talk about the native load and what we did.

We had lots of different ideas. I think you've combined the best of them.

MR. PEDERSON: If I could start with the native load portion of that. Native load, there were numerous comments regarding whether or how to account for native load. What we heard at the technical conference was, that it's not very easy to separate generation that is going to serve native load versus generation that is going to compete in the wholesale market.

Those generators tend to swing back and forth between the markets. It's not easy to segregate these markets.

The pivotal supplier analysis we came up with the draft order that proposes a proxy for native load which would be based on the average of the native load peaks, daily native load peaks during the peak month of the year.

The pivotal supplier analysis looks at the annual peak as the basis to determine whether the applicant is pivotal. Using the average of the native loads gives us a better feel for what actually is happening in the market, and I think the draft order talks about the fact, or the belief that where market power is very likely the most, the biggest opportunity for market power is leading up to that needle peak.

The needle peak isn't known until after the fact so we had to come up with some way to account for that. On the market share side, the market share is looking at seasonal shares. Comparing an applicant with others in the market for that piece of the screen the native load that one takes out is the minimum peak day for the season.

The thought behind that is the minimum native load peak day of the season, the thought there is the rest of the generation that the applicant owns is available for the wholesale market for the rest of that season so we get a good comparison of what the applicant looks like, compared to the other competitors in the market.

I hope I've answered that part of your question and I'm going to turn over the delivered price test to David Hunger.

MR. RODGERS: Before we go to David, I was just going to add a couple of other thoughts on the native load issue. One you may recall at the technical conference staff asked questions of some of the panelists about since there is this portion of generation that investor-owned utilities have that is committed and obligated to native load, would it be appropriate then for the Commission to just say that we will not allow wholesale sales to take place from that generation since it is committed presumably. And the answer we got back was no. That would not be a good idea.

In fact, as Jerry noted, the generating units, the same ones that meet native load are also the same ones that are used to make off system wholesale sales. The other thing I would mention or highlight is Section F of the draft order, specifies what the native load protections are. They are set forth in this order. There are several of them but in addition to the native load deduction which we allow under both of the screens in this order, we also note that native load customers are protected when utilities are purchasing power in wholesale markets because they can be assured that they are going to be able to buy that power at just and reasonable rates, and not from someone that has market power.

We also note that native load customers will be protected by the greater transparency that will be provided going forward. For entities that lose their market base rate status by virtue of the greater accounting and reporting requirements, that they'll have to make sure that the Commission will provide greater transparency for all regulators, not just FERC regulations.

COMMISSIONER BROWNELL: Thanks Steve. I think it has gone a long way to answering the various issues that were raised, including and most importantly our primary responsibility of protecting native load but also allowing those protections to work in both unrestructured markets, the monopoly markets and the restructured retail markets, which I think is also important.

You've done a great job here and I think that's critical.

MR. HUNGER: On the delivered price test. The delivered price test is a tool the Commission uses for analyzing the effect on competition in its review of mergers and acquisitions and dispositions of jurisdictional facilities under Section 203.

What the delivered price test really does is determine who can actually compete in a market rather than looking at just total installed capacity or uncommitted capacity.

It takes running costs and market prices into account. For instance, in an off-peak period when a competitive price might be $25 a megawatt hour, a peaking unit with a high heat rate that has a running cost of $90 per megawatt hour, couldn't possibly compete in that market. So it takes that into account.

You start by assuming a market price for the relevant geographic market. That market price differs at different time periods, winter periods, summer periods, shoulder and then peak, super peak, off peak. So you take a look at historical data concerning what a reasonable price is in that market and then ask, who can compete in that market.

So you start with a price of $40 per megawatt hour, ask what generators, what suppliers can produce within 5% of that number, so that gives $42 per megawatt hour. So who can really compete? Who could give a competitive response to an attempted exercise of market power in the sense and taking transmission constraints into account. So it does more for the job of figuring out who the possible suppliers are in a market and from there, it determines just how much capacity, what we call economic capacity that can really compete in a given market, in a given time period, in a given load condition.

How much capacity they have? From there you can generate market shares with those numbers. You can do a pivotal supplier test. You can generate market concentration numbers, the Hurfendahl index that we use in the Section 203 but we'll get more robust numbers coming out of the delivered price test and it's the second state.

If you don't pass one of the initial screens, then you would go to the delivered price test. We don't want everybody having to do a delivered price test. It's costly, it's time consuming, but for cases where the initial screens have indicated this rebuttable presumption of market power.

This is a way for both applications to come back and say, well with more robust numbers, it turns out that I don't have market or I only have it under certain conditions.

On the other hand, it will give both applicants and the Commission and interveners a way of making sure that that they are comfortable with the numbers.

COMMISSIONER BROWNELL: Correct me if I'm wrong because we were working on this adjustment. If you feel you are not possibly going to pass the first two sets, you can go directly to the delivered price test. Is that an option?

MR. PEDERSON: I think the draft order says that you can skip the first two and except the presumption of market power, and go to a number of options, one of which would be the delivered price test.

CHAIRMAN WOOD: You can even go past that and go straight to the mitigation phase if you know and avoid kind of the stretch of time. Just go straight o mitigated input.

MR. PEDERSON: Absolutely. There are a number of procedural options at every step. They can pretty much take advantage of all of them.

CHAIRMAN WOOD: That's good.

COMMISSIONER KELLIHER: Mr. Chairman I support the order. I just wanted to point out some of the changes I think are most important. The order does use two screens to replace the SMA test for the two screens and I think the use of two screens is appropriate since market power comes in different forms.

The first screen, the pivotal supplier screen, it seems like it will adequately measure market power during periods of peak demand while the market share screen will probably more measure market dominance.

I also support the changes with respect to native load. The SMA test did not account for native load with respect to obligation and studied the generation market power of the applicant and I think we addressed both in the new screens. The order does eliminate the exempt sales into RTO and ISO markets.

I agree with that because I think the Commission cannot delegate its legal duty to prevent the exercise of market power in wholesale power markets. The order also changes the default mitigation to be imposed in the event that an applicant fails and is found to have market power, the default mitigation in the order is more traditional forms of cost based mitigation.

Also mitigation is not limited to spot markets. That was an area that some of the commenters had addressed and it does extend to forward markets. I think that's appropriate since I don't believe it's reasonable to assume that entry will eliminate the potential for forward exercise market power in the markets. I commend the staff and I'm happy to vote for it.

I also commend the Chairman for (*) to bring this hearing order out.

CHAIRMAN WOOD: We've been waiting on your wisdom for a long two years Joseph. I'm glad we got it. (*) meeting. I can't add much more much to what you all have said. I appreciate the hard work and it's been an interesting two plus years. A lot has happened in the last two years in the shadow of 9/11, California, Enron, the financial market meltdown and doubling of the price of natural gas and a blackout which I really can't, quite frankly, as crazy as I try to tie the blackout into SMA, but perhaps I can with some alcoholic help.

LAUGHTER.

CHAIRMAN WOOD: A lot has happened along the way. We got smarter, we head up a shop here to help enhance our ability to be looking at these markets on a proactive basis but we've been in a lot of litigation relating to market-based rates, including some pending cases as well.

We've looked at market behavioral rules, both comprehensively in the S&B context, but also directly in the orders we put out last November on market behavior and gas and electricity. But all these things are really about one common theme, fulfilling our Federal Power Act responsibility to ensure that the mechanisms that are prevalent now which our markets result in just and reasonable rates.

We talk about native load. There is a lot of native load out there. There are big utilities, little tiny utilities. The big utilities aren't the only ones who ought to be protected, the little ones should be too.

And so, this process that we are going through and that we initiate in the clarified process that we put forth today is fundamentally fulfilling our charge that where markets are not competitive and (*) are not always competitive, we can't sit on the sidelines and just go, tut, tut. We have an obligation to do something about it and many customers, many wholesale customers out there counting on us doing our job and doing it well.

This is a very solid, methodical fact-based, good economic policy-based outcome from a very robust, fruitful discussion, that I will confess forced me to change my mind on a few issues and I totally support every take in this order. Importantly, we're looking at the broader issue. We spent a lot of time focusing on Prong 1 but as an important companion here, we're looking at Prongs 2, 3 and 4.

Again, as well as asking, is Prong 1 good for the long term. It's just pitched here as an interim charge but is it one that we want to stick with for the long term as well. But looking at the full package together, clearly looking back, I wish we had done the full package at the onset. But the hub and spoke method was the patient in ICU and it needed to be fixed.

The patient is now rolling out of the hospital and ready to get back to work because we do have plenty of dockets that are waiting on this decision. So I appreciate.

COMMISSIONER KELLY: Mr. Chairman I want to revise my last comment. I didn't mean to suggest that Sudene actually, improperly participated.

LAUGHTER.

COMMISSIONER KELLIHER: I apologize for that.

COMMISSIONER KELLY: That's quite all right Joe although I am recluse from this case and I have not been able to participate in it, but I do look forward to reading and becoming very familiar with the order you all issued today.

LAUGHTER.

CHAIRMAN WOOD: Ready to vote.

COMMISSIONER BROWNELL: I am but the floor is yours sir.

CHAIRMAN WOOD: I'm done. Ready to vote.

SECRETARY SALAS: Mr. Chairman, let me clarify for the record, we will take this vote separately. Commissioner Kelly is recluse from participating in E-1 but she will be participating on E-2. May I please have the votes on E-1?

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: Those for E-2.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye. Very nice job. Let the analysis begin.

SECRETARY SALAS: The next item for discussion is G-1, Georgia Public Service Commission. Presentation by Joel Fina accompanied by Scot Koves, Anna Cochrane and Karen Giblin.

MR. FINA: Good morning Mr. Chairman, Commissioners. G-1 concerns a petition for declaratory order filed by the Georgia Public Service Commission. The petition requests that FERC address the following question. "Whether the FERC would preempt the Georgia Commission if the Georgia Commission adopted a plan that provided for the permanent assignment of the interstate capacity assets currently held by Atlantic Gaslight company to certificated natural gas marketers and placed conditions upon that assignment of the interstate capacity assets."

The draft order answers the Georgia Commission's question in the affirmative based on t he FERC's exclusive jurisdiction over allocation of interstate pipeline capacity and the FERC's capacity release rules and regulations.

In addition, the draft order provides guidance regarding the application of the FERC's policies and directs its gaslight companies to file a capacity release rate schedule with the FERC. Thank you.

CHAIRMAN WOOD: Thanks Joe, the only reason I wanted to bring this up, this has been kind of a recurring event every year. What to do about the Georgia gas program and I appreciate everybody's willingness to kind of see what we can do to actually, rather than just say yes or no, give them some guidance about the structure. So the last three or four pages of the order do just that.

It may not be the guidance that's helpful now, but I just want to say to the Georgia parties, we want to work to support that effort. It is the Georgia state retail gas program as identified by the Center for the Advancement for Energy Markets as really the bright star in the world of retail choice.

I think we have an obligation as the brother and sister regulator of the states to really support Commissions that take that hard step of moving forth into undoing a century of monopoly power on the retail level and enable residential, commercial, and industrial customers to choose their energy supplier just as they choose in every other aspect of the their supplies.

We need to support them in proper ways and now we've got established years of wholesale regulation policy that has done a good job in the gas markets. Clearly we are supporting wholesale competition. I just want to make sure that we continue to be as vigilant as we can about the interface between what we do on the wholesale side and what the states do on the retail side.

I think actually we've had good success with this in those states. We've had good success with this on the electricity side where that's happened as well. But I just want to kind of say publicly, I think this program, because it has kind of rung the bell, of a good report card rating and I happen to trust in something I just want to say that we are going to engage in a continuing dialogue, rather than just see this on an annual basis and spend a lot of good time (*) with our policies. So this will initiate that dialogue. So let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is C-4. As required by law, Commissioner Kelly is recluse from this case. This is a presentation by Bern Bosley, accompanied by Bu Ngayen, Joseph O'Malley, Chris Serby and Bob Christin.

MR. MOSLEY: Good afternoon, Mr. Chairman and Commissioners. Item C-4 is a draft Order responding to a request made by Weaver's Cove Energy and Mill River Pipeline for a preliminary determination or PD on the proposals for a Section 3 LNG import facility and a Section 7 pipeline facility, respectively.

The draft Order also responds to the request made by the Honorable Edward M. Lambert, Jr., the Mayor of Fall River, Massachusetts, that the Commission hold a hearing to clarify its timeframe for the environmental review of Weaver's Cove's proposal.

Weaver's Cove wants to commence service in November 2007. To meet that goal, it would like to begin construction of the proposed LNG facilities in late 2004. With that objective, Weaver's Cove sought a PD by March 31st, 2004. Mill River plans to commence its pipeline transportation service concurrently with the Weaver's Cove LNG service and likewise requests that the Commission issue a PD at the same time.

The draft Order denies Weaver's Cove's request for a PD on the basis that the types of issues typically addressed in PDs such as rates, terms and conditions of service, and other non-environmental matters are not present in Weaver's Cove's LNG proposal.

Weaver's Cove is proposing to use a business model that is consistent with one approved by the Commission in the Hackberry Decision. In that decision, the Commission modified its policy for regulating LNG import facilities so that they would treated as though they were akin to production facilities.

As such, it would not be necessary to require LNG terminal facilities to offer open access terminal services or to maintain a tariff and rate schedule for such services. Instead, the Commission granted Hackberry the authority to provide LNG terminal service at the rates, terms and conditions mutually agreed to with the customer.

Since there are no non-environmental issues to address in the Weaver's Cove proposal, there's need to issue a PD. The draft Order also denies Mill River's request for a PD, while the draft Order recognized that the pipeline delivery laterals preferred by Mill River are an integral part of the overall project.

It find that there are not the kinds of facilities at issue in major construction projects that would benefit from the PD process. Our only issue related to the laterals will be addressed when the Commission issues its Order in the Weaver's Cove proceeding.

Finally, with regard to Mayor Lambert's request, the draft Order finds that it's not necessary to hold a hearing to address the timing of the Commission's environmental review of this project. We assured Mayor Lambert and the people of the City of Fall River, that the Commission will not rush its review of the proposed Weaver's Cove project, and that safety is an integral part of that review.

The draft Order points out that the Commission actually began its environmental or NEPA review of the project under the Commission's NEPA pre-filing process back in May of 2003, six months prior to the actual formal filing of the application in December 2003.

The draft Order also notes that the NEPA pre-filing process does not necessarily shorten the time period that is required for Commission Staff to complete its environmental analysis. Rather, the NEPA pre-filing process allows the Commission to process the application in less time after it is filed, because the environmental record is completed closer to the filing date.

The draft Order also assures Mayor Lambert that our responsibilities under NEPA have not been short-cut by the use of the pre-filing process, and that the Commission will still perform a complete environmental review of the proposal.

This concludes my presentation. We are available to answer any questions you may have.

CHAIRMAN WOOD: Where around the DEIS time line was this application?

MR. ZERBY: We have -- the DEIS is still under preparation. We had an administrative draft that went out to the various operating agencies, the federal and state operating agencies, and we are still reviewing their comments.

We've had good participation from virtually everyone at the federal and state level on this project.

CHAIRMAN WOOD: Good. We'll see it soon, then. I think it's a process matter. We've got these requests coming in from a number of them. This was the first. I think it was important to set it in a formal order to let the world know that if you're going the Hackberry route, we're not going to kind of slow down but try to do another Order in the process here, but stay focused on the critical environmental safety and land owner issues.

So I think we don't need to read a whole lot more into this than what we're doing, but just to try to politely answer the question that we're going to keep our eye on the ball, rather than stop on the detours. So we appreciate your serving that up for us.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

We'll take a very short break because we do have a tight day here. We'll come right back with the two presentations from the market monitors in New York and PJM.

(Recess.)

CHAIRMAN WOOD: We'll go back on the record. We're delighted to have with us, from two of our star markets, Joe Bowring from PJM, and David Patton, the Independent Market Monitor from the New York ISO, and Steve Balser, who is the Manager of Market Monitoring inside the New York ISO, to visit with us, as we do about two or three times a year with each of the five -- now six regions.

What's going on in the markets? I know we've got kind of a full day here, but why don't we shoot, fellows, between the three of you all, to try to wrap it up at about 2:00 or so. I want to just encourage -- what we've done with these guys is ask them to give us an update on some historical performance in the markets, as well as some forward-looking thoughts about issues that are kind of bubbling.

Feel free to jump in through the presentation and just ask questions and say anything. It's pretty informal. We are always glad to see you guys back here.

SECRETARY SALAS: Please let me note for the record that this is Number A-3 on the agenda. Who's going to go first? Joe?

MR. PATTON: Okay, first I want to say that I appreciate the opportunity to deliver some of the highlights of the 2003 State of the Market Report for the New York ISO. These discussions are always provocative and important.

What I'm going to try to do is limit my presentation of various analytical results to 15 or 20 minutes and to allow plenty of time for you all to ask questions.

(Slide.)

MR. PATTON: In fact, you should feel free to interrupt me. I'll probably be talking relatively fast to try to get through it. I also want to say that I appreciate the support on this report from the market monitoring unit of the New York ISO who provided us with a great deal of support and collaboration.

The first slide I want to show is actually Slide 4.

(Slide.)

MR. PATTON: What this slide shows is the average day-ahead electricity prices in East and West New York. East New York prices are in maroon there, and plotted against a natural gas price that's plotted against the right axis.

It's a little bit difficult to read, but what this shows is that electricity prices over the past two years have been heavily driven by movements in fuel prices.

This is what you would expect, particularly in New York where natural gas prices were 70 percent higher in 2003 than in 2002, and oil prices were 24 percent higher, on average, which drove energy prices, electricity prices, higher in both East and West New York.

The peak for our average monthly electricity prices was in February and March, which is unusual, but that corresponds with the peak in natural gas prices that you can see there, which in February, averaged over $10 a million Btu. In 2002, we were down in the $3 range, so it's a remarkable increase in natural gas prices.

The second peak occurred more normally in August at a lower level, due to the higher load levels. What this chart also shows is the congestion that you can see between the Eastern locations and the Western locations in New York.

The prices in Eastern New York were 32 percent higher than in Western New York, due to two primary constraints, the Central East constraint that divides East and West New York, and then the constraints, more importantly, the constraints that go into and within New York City. I'll talk about those a little bit more in just a moment.

(Slide.)

MR. PATTON: This shows a price duration curve for the highest priced five percent of the hours in the last three years. For anyone who's not familiar with a price duration curve, what it shows you is the number of hours in the X-axis where the price is equal to or higher than the price on the Y-axis.

For that reason, the zero or the one-hour point is usually showing you something around $1,000, because there are very few prices at those very high levels. What this shows you is two things, really:

In 2003, which is the green line, it is across the entire year and across this chart in the flat area, the 2003 prices were 20 to 30 percent higher than 2001 and 2002, and it shows the sustained impact of the higher natural gas and oil prices.

The other important thing to see is that the green line shows very few prices at high levels, although we implemented scarcity pricing provisions in New York to ensure that when we're short of reserves and we can't meet both our reserves and energy requirements. Though we implemented those prior to the summer of 2003, we were never short in 2003.

That's primarily due to the load conditions that I'll show you in just a moment. The price is actually -- if you look at the prices above $500 a megawatt hour, there are 11 hours in 2001, six hours in 2002, and there should have been more, had we proceeded correctly, and there were only three in 2003, which has a significant impact on the cost recovery of generators. That plays a fairly important role in that.

Go ahead two slides to Slide 8.

(Slide.)

COMMISSIONER KELLY: David, has the East-West price differential led to transmission construction?

MR. PATTON: It's led to some construction on the Central-East Interface. The more significant congestion is in New York City. Recently, the new project, the construction project, didn't succeed in getting bids by participants to invest in that line. That would have added a significant amount of capacity into the City.

There has been transmission added between Long Island and Connecticut in response to the same constraints, sort of the New York City, Long Island area. That's the high-priced area, but I think the area of transmission investment is an area that still needs more work in terms of developing the right incentives and the right market rules and the right combination of regulated investment and market-driven investment. It's hard because those two crowd each other out.

COMMISSIONER KELLY: I was going to ask a followup question. What role does the New York ISO take in transmission planning?

MR. PATTON: Each of the ISOs are part of the planning process and conduct planning studies so that I think all of the ISOs have a transmission plan that includes each of the proposed projects and identifies those projects necessary for reliability and those that have been proposed for economic reasons.

So they play a relatively fundamental facilitating role in studying and coordinating that process.

COMMISSIONER KELLY: They don't drive or encourage? Is it more passive than active?

MR. PATTON: I would say it's more active in the area of investments that are needed for reliability. There's more variation in how the ISOs approach economic investments.

COMMISSIONER KELLY: Thank you.

COMMISSIONER BROWNELL: Actually, Commissioner Kelly, that was pretty much my question. We've heard some concerns that the planning process is not sufficient to address either reliability or economic construction, and it isn't regional and it is largely utility dominated, as opposed to ISO dominated. Is that continuing to be true? I know there were concerns raised when we last met in New York. Has there been any progress made? It's an independence issue, too.

MR. PATTON: Sure. The extent to which the ISO is helping facilitate the process, it's less utility dominated than it is in an area without an RTO that is doing the facilitation where it's almost entirely transmission-owner driven.

The part of the seams work that New York has been doing with its neighbors, though, is to try to broaden and make more regional, the planning process. I'm not sure exactly what the status of that is, but I know there is work underway in that regard.

MR. BALSER: I think the ISO's participation in the area where reinforcements are necessary for new generation, is very strong. We have a set of rules and guidelines that people have to follow. I think that probably in the area of bulk transmission, I think there needs to be more work done.

In fact, there is a plan underway right now to beef up that area and come to an agreement on what the ISO's role would be in that.

COMMISSIONER BROWNELL: As we deal as we have this morning with market power issues, to the extent that there isn't an independent regional planning process that evaluates all options, one would have to question whether then we've got to look at some market power issues there, even given the structural change, which we certainly commend, and the other good things that are happening.

Maybe we can talk about it in New York.

MR. PATTON: The next chart that we're looking at is Slide 8.

(Slide.)

MR. PATTON: It is a load duration curve. It's similar in design to the price duration curve. This particular chart focuses on the summer of 2002, versus the summer of 2003, so it shows more hours than the price chart did.

But the important thing to see here is how dramatically different the loads were in 2003 and 2002, and why -- one of the main reasons we didn't have shortage conditions in 2003, is, if you look at the hours in which the loads in New York were over 30 gigawatts, there are three hours in 2003 and 25 hours in 2002.

The corresponding relationship, as you go to the lower load levels above 28 gigawatts, the peak conditions were far less tight and extreme than they were in 2002. 2002 was actually a worse than normal year and 2003 was much better than normal.

(Slide.)

MR. PATTON: Slide 10 is an all-in price. Sometimes we call this the total market cost metric. It is the cost per megawatt hour for load during each of these years, 2002 and 2003.

It includes ancillary services and other costs, including the administrative costs of the RTO; uplift, the average energy price and capacity, which is the other large component of the costs.

What this shows you is that the prices statewide in New York, the all-in price, was almost 30 percent higher in 2003 than in 2002. Nearly all of that increase is related to an increase in the average energy prices. Again, those are driven primarily by the fuel price increases.

The capacity values are very similar in the two years. There was a significant change in the capacity market which was the implementation of the demand curves for capacity, but what we thought were higher purchases resulting from the demand curve, but lower average prices for capacity, in general in 2003 and then in 2002, which caused the capacity costs to be very similar between the two years.

That is a good segue into Slide 13.

(Slide.)

MR. PATTON: This shows the net revenue that three representative generating units would have earned in 2002 and 2003, in New York, at, in this case, two locations within New York City, and, in the next slide's case, two locations outside New York City.

This is an important chart, because it shows what the incentive to invest in new generation is. The three generators are 7,000 heat rate units that are meant to correspond to a new combined-cycle unit, a 10,500 heat rate, so, essentially, a higher operating cost, which corresponds to a new gas turbine, which is a peaking generator.

Lastly, there is a 12,000 heat rate, which is meant to reflect an existing gas turbine. All of these units are assumed to be natural gas-fired units that you would see in terms of the net revenue. Net revenue is defined as the total revenue a generator would earn, minus its operating costs. You can think of it as a profit measure.

MR. PATTON: What you would see if we did this for fuel types that meant revenue for coal units, hydro units and to a lesser extent, coal units. Significant the net revenue for gas units did not up significantly because their costs were going up at the same time the energy price was going up.

The other thing that's important in this chart that makes it slightly different than the chart you'll see from some of the other market monitors is we assume that gas turbans buy gas intraday at a premium which lowers their profits. You'll see a dashed area on top of the two higher cost units. That's how much their profit is reduced because they have to pay more for gas.

What we find from this chart is that generally the new gas turban in New York City did not earn enough net revenue in 2002 to recover its costs of investment. That would be a bigger concern in New York City than outside New York City because New York City is capacity deficient. And there is a surplus capacity outside New York City. So if you find they can't recover their costs outside New York City, that's not necessarily a concern.

It may not even be a concern in New York City for two reasons. One is that capacity demand groups are being phased in so if capacity revenues, if they remain deficient in New York City would be expected to rise over the next year or two.

And secondly, we have no shortages in New York. If we did in fact have shortages, which I would expect in a normal year, that would produce substantial additional net revenue for the generating units.

The other thing is, it's not clear. If you look at other new units, it's not clear that they will not earn enough money to invest. For example, the combined cycle unit here, it's net revenue in the one location is over $300,000 per megawatt year. The cost that we think we have a handle on for building a combined cycle outside New York City is about $100,000 a megawatt year. But the cost to build in New York City is multiples for any technology if you can even build.

We don't know what the cost of building a new combined cycle in New York City is but that may be sufficient even in this sort of year.

MR. HEDERMAN: Excuse me on that point. How do we get a better handle on that cost? Is it going to require one being built?

MR. PATTON: That's interesting. That's how we learned what the cost of building a gas turban was and the New York Power Authority built gas turbans in the city about a year and a half ago. Everyone was operating under the assumption that the experience in New England of building a gas turban, which would require something like $75,000 a megawatt year. That was about there requirement NYPA built their gas returns and after some period of time, we learned, based on their cost, they would require about $200,000 a megawatt year to make the loads investments profitable.

They were some debate as to how they incurred higher cost because they were a public agency or lower cost because they had advantages a private agency wouldn't have but it illustrates the relatively dramatic distance in building in a load pocket area like New York City. These areas exist in other markets.

MR. LARCAMP: These are t he 49 megawatt units? Were the New England units similar in size?

MR. PATTON: There were similar units but generally they were located in either Maine or in other areas where land is much cheaper and access to natural gas fuel is easier. Outside New York City the combined cycle units look like they are right on the cusp of being profitable in the east, in the capital zone, which is east New York, above New York City, and not in west New York.

If we go on to slide 16.

SLIDE.

This shows the equivalent forced outage rates over the last six years in the New York markets. The vertical dividing line there represents approximately when the New

York ISO markets began operation. The bars are the rates in New York State. In case you can't read the scale on the side, they dropped from somewhere in t he range of 11 to 13 percent in ;98/'99 to closer to 5% in 2002 and 2003.

The divergence between New York State and New York City in 2002, which I point out in that first bar, is due to the Indian Point nuclear unit that was out in the year 2000.

But I think what this chart shows you is a couple of things. One is that the competitive markets give a much higher incentive to maintain higher variability for the units. That incident was enhanced when the capacity market shifted to the UCAP metric of buying and selling capacity. UCAP stands for unforced capacity.

Any generator who experiences a high rate of forced outages will have the amount that they can sell on the capacity market berated. It's a fairly direct incentive to make the investments necessary to make sure that your plant is available.

And it contributes to the low force outage rates. Moving to slide 18.

SLIDE.

This shows you the congestion costs in 2001 to 2003. While we may have lost it sometimes power point -- if you just flip on the screen you could probably go to it. Slide 18 shows a stacked bar with two components. The first is the dear head congestion rents that are collected in the market.

The second is the balancing congestion costs which is congestion that is collected in the real time market. These costs went from $310,000,000 in 2001 to $525,000,000 in 2002 to $688,000,000 in 2003. That increase doesn't necessarily indicate that congestion is a bigger problem now than it has been in the past.

The biggest source of that additional congestion is the modeling of the transmission constraints within New York City. Before, what we did in New York City was manually dispatched generation out of merit to make sure we didn't overload those facilities. In the middle of 2002, those constraints were put into the model, which caused locational prices to reflect the congestion. So instead of seeing the congestion in uplift, which is what you'd see when you manually dispatch generation, you'd see it in market prices.

There are lots of benefits to doing that. But one of the things it will do is indicate the value if your congestion is going up. The interesting thing about this chart is the balancing congestion costs. Those should be fairly close to zero. If the real time market model and the day ahead market model are consistent with one another, you end up having to collect those sorts of costs because the transmission limits look lower in the real time than they did in the day ahead.

So you schedule power in the day ahead but now you have to pay people to under schedule. This is an issue largely because of the fairly wide difference between the day ahead model, which is a very modern, sophisticated model versus the real time model, which is built off of essentially 30-year old technology and one of the benefits of moving to the RTS, the real time system in New York, which you all have already approved and will be happening in the fall is, they're going to have a real time model that is built off the same platform as the day ahead and much better consistency between those two.

MR. HEDERMAN: David I want to ask, do you have a sense of how much is due to the modeling problems and how much is load pocket congestion?

MR. PATTON: The balancing congestion cost.

MR. HEDERMAN: Is that entirely modeling?

MR. PATTON: Nearly all of the balancing congestion cost is modeling related. The other thing that would cause balancing congestion costs are assumptions about loop flow. That is occurring because of the dispatch of resources and load outside of the system. That turns out not to be correct if you assume there is going to be no loop flow and then there is, that eats up some of your transmission capability and can cause those costs.

I did establish that it looked like the limits were more restricted in the real time than in the day ahead, but I did not try to divide the costs between potential loop flow impact versus the modeling impacts.

COMMISSIONER KELLY: David, is New York City still pricing their congestion costs in m annual dispatch?

MR. PATTON: No, that was the change made in the middle of 2002. That's why you saw the congestion cost for 2002 and 2003 go up quite a big.

COMMISSIONER KELLY: Did the energy prices come down?

MR. PATTON: The energy prices in New York City have gone up because they now reflect the congestion they did not reflect before. The energy prices outside New York City have not changed a great deal. But in New York City they're higher because they're showing the congestion now.

CHAIRMAN WOOD: Did that used to be uplifted?

MR. PATTON: Yes.

CHAIRMAN WOOD: The total bill is the same but just broken up differently or is it actually higher?

MR. PATTON: It would be hard to tell. If you compared the congestion cost to the uplift, the congestion costs generally is going to be higher than the uplift for a coupe of reasons.

One you're setting a market clearing price now for congestion so now there is a sustained high price. Everyone gets paid, which is good because it's sending better incentives rather than just paying the expensive units out of uplift.

The thing that makes it difficult to tell, a matter of fact the whole thing is that TCC is coming and saying, has the congestion costs go up, you're rebating a large portion of that back to the load. With all the transmission rights coming into the city.

COMMISSIONER BROWNELL: Are we seeing behavior yet in response to the price signals?

MR. PATTON: Behavior in what regard?

COMMISSIONER BROWNELL: To eliminate a reduced congestion.

MR. PATTON: Yes I think certainly there has been a desire to build as much as possible in New York City and there has been construction by both NYPA and attempts by others to invest in generation. I think we are getting, you know it's a difficult area because it's extremely difficult to build anything there. Certainly to find a new site, most of what we see built is on existing sites or repowering of older units.

But I think the incentives are there. One important thing to notice, if you didn't notice it on the net revenue chart, we talked about this in the technical conference on load pockets. This is probably one of the best examples of a load pocket is New York City.

The dramatic difference in capacity revenue for units in New York City versus units outside New York City. That is the primary reasons why you don't have dockets from New York City like you do in New England, where generators en-masse want RMA contracts because the locational capacity requirements give you a chance to reflect the unique value of resources in that area.

Where if you have a capacity market with no locational requirements, everyone gets paid at the low level. The existing units that you have to have for reliability don't get the signal that they are needed and so you get RMR contracts, which is not good for transparency signals, or they go out of business. But generally we don't let them go out of business, but in New York, that is the primary reason why the existing generators in New York can sustain themselves, is the locational capacity requirements.

COMMISSIONER KELLY: What I guess I'm concerned about is, are the signals having the desired result that we want?

MR. PATTON: Yes I think they area. I think in order to allow them to play out to a greater extent, what we really need to do is identify and address the other barriers to investment. I think the economic signal is the one thing that is under our control and we've done a fairly good job I think of making sure that it's there efficiently.

COMMISSIONER BROWNELL: Nobody is building anything, that's what he's trying to get at. Nobody is building anything right?

MR. PATTON: If you look over the past three years, there has been some construction and there are attempts to build and proposals to build. Those proposals are being stopped because in general, people are saying it's uneconomic. In terms of transmission, it is important to make sure that transmission investments can compete fairly with generation investments. That is one thing that is required to do that, or one idea to think about in that regard, is the capacity value, making sure that to the extent that transmission investments can relief the capacity needs in a load pocket area, that they get the benefit of the capacity that they create into those areas.

So, I think there are a lot of reasons why investments isn't at a level we would hope it to be at. For one, most of the potential investors have very poor credit ratings so the cost of capital is probably at a higher amount that I have eve seen it.

Okay I just have a few minutes left but I have no more pictures but I wanted to just review some of the other major conclusions from the report. I think the first conclusion, based on our analysis of physical and economic withholding that may have occurred in 2003 is that the New York markets continue to perform competitively.

The automated mitigation procedures didn't mitigate any participants in 2003. The mitigation that primarily occurred was in the New York City area where you have a number of suppliers who are pivotal at virtually all hours, so the frequency of mitigation in New York City is much higher.

What I think is remarkable and is, I think an endorsement on the Commission approach in this area is that you can have a market like New York City and the fairly low load pockets within New York City where clearly they would fail any test for competitiveness and there is a relatively extreme degree of locational market power in those areas.

Yet, through the mitigation measures, the performance in New York City is competitive. So it allows you to have a competitive market even in an area like New York City where the only other alternative is fairly extreme divestiture, which I'm not even sure you could solve some of the locational market power issues taking that approach.

Secondly, the day ahead and real time energy prices exhibited good convergence. We talked a little bit about potential inconsistencies between the day ahead and real time models.

One of t he important things in the New York market and I think in the PJM market and the New England markets as well, is that virtual trading really resolves a lot of issues. The reason the real time prices an the day ahead prices were not out of line with one another is you had market participants who can freely enter in the day ahead market and arbitrage between those two markets, so you are able to overcome some of the issues that may exist with modeling inconsistencies.

The demand curve for capacity that was implemented was very successful in stabilizing capacity prices and facilitating convergence between the multiple rounds of the capacity options which had been at least a number of the capacity options had been fairly illiquid and that the pricing had been volatile.

Two more conclusions. One is that the real time prices between the adjacent regions between New York and other regions still are not efficiently arbitraged. Particularly, we focused on New England, who implemented SMD locational pricing which some had thought would resolve much of the problem across the same between New York and New England. It did not. Largely because the problems have to do with the timing of the scheduling, the risk that participants have to take when they schedule, and the export fees between the areas.

I think the commissions move in the New England order to eliminate export fees and facilitate coordination between the RTOs is extremely helpful.

One of the recommendations of this report is for New York and New England to continue to develop virtual regional dispatch which is a means to coordinate the physical interchange between the markets to ensure it is efficient.

Then lastly, I would say the New York ISO demand response programs remain extremely effective but in 2003, they were essentially not needed because of the low loads. I think they were called only during the black out restoration period to ensure that power was restored in an orderly fashion. Those are the principal highlights of the report.

(Meeting adjourned at 12:13 p.m.)

CHAIRMAN WOOD: Thank you, David. Time line on VRD.

MR. PATTON: That's a good question.

CHAIRMAN WOOD: The export issue just from the e-mail today maybe getting put to bed pretty quick, which is very good news.

MR. PATTON: I hope so. And, as far as VRD goes, in part, it depends how sophisticated an approach you take. What I had originally recommended was a fairly simple approach. It's gotten more sophisticated, requiring more software to be developed, which causes it to compete with other priorities like the development of reserve markets in New England, which I would probably put as a higher priority to the energy, given a choice.

So it's unclear, I think, exactly what the timeframe is. The ISOs are in the process of prioritizing their software resources and figuring out where it's going to fall. But, I think, for both New York and New England, it's in the top three of their priority list.

CHAIRMAN WOOD: Great.

MR. HEDERMAN: One more question. Could you walk through your reasoning in a little more detail about how the mitigation is leading to a competitive result in New York City, if I heard you correctly.

MR. PATTON: Sure. The structure of mitigation in New York employs conduct and impact tests that first seeks to determine whether a participant is engaging in withholding before mitigation is even considered. Then, secondly, whether that withholding would raise prices materially. If those two criteria are met, mitigation would be imposed.

So, in many hours, and those tests are only employed for the load pockets on New York City as a whole when constraints are binding that would give somebody local market power. So what the mitigation allows is when the constraints aren't binding. The generators in New York City effectively face competition from generation anywhere in the state.

Certainly, in the East, the mitigation would not be employed. Secondly, when the constraints are binding, the mitigation prevents the withholding and, in our evaluation of -- you'll see in the report, I think, the most important charts are the output gap figures. The output gap measures how many megawatts that appear to be economic are not producing energy. So it's a measure of economic withholding, either are not producing energy or are setting the price at a price that is significantly higher than the competitive bench mark level.

What you see in those charts is that, generally, the levels are very low. Secondly, they decrease as you move towards the peak and it's really in the peak when you'd be most concerned that participants would have an incentive to withhold. So it gives you comfort that what you're seeing is behavior that's consistent with competitive behavior.

CHAIRMAN WOOD: Thanks.

MR. LARCAMP: To build on that, I think Slide 13 notes the importance of the UCAP revenue stream to the behavior of those generators within the load pocket. I think you suggested that they're getting a very significant percentage of their revenue stream from the UCAP.

MR. PATTON: That doesn't really effect their behavior in the energy market because those two markets are separate. When you receive capacity, it's not going to effect your behavior in the energy market if you're going to seek to maximize your profit.

MR. LARCAMP: But, if you don't get the revenue stream in the capacity market, you are that much more dependent on your revenues in the energy market. Correct?

MR. PATTON: On a need basis, that's right. But businesses don't operate on what I need. They seek to maximize their profit. So, if somebody -- the only thing that is affected by whether they're recovering their full allotment would be a decision to shut down or stay in operation. They're still going to try to make as much money in the energy market as they can.

What's important about the capacity market is New York City, like a lot of load pockets, has capacity requirements on a daily basis that we turn on generation to support that area. That's not built into the energy price anywhere. Those were liability requirements. They're not priced anywhere. If we could magically make the market competitive in New York City, if you were to wipe out the capacity market, there would be a major service that's being provided, a reliability service that's not being priced and you wouldn't be able to sustain the level of capacity that you need in that area. That's the most important dimension of the UCAP revenue. It attempts to capture, in market results, a very important requirement of the liability requirement.

In fact, when you commit to meet this requirement on a daily basis, you tend to dumb down the energy price or reduce the apparent congestion. You're bringing on more supply in that area. In fact, we see that in New England, Boston, and Connecticut. There's very little congestion because they commit so much generation in those local areas to meet their reliability requirements that the energy price isn't indicating the need in those areas.

CHAIRMAN WOOD: Joe? Thank you, David.

MR. BOWRING: Good afternoon. Thanks for the opportunity to be here. I'll try to go fairly quickly through the highlights and the conclusions of our state of the market report and look forward to your questions.

(Slide.)

On Slide 2, I have the basic conclusions we've reached. Going through the markets, virtually all of our market results were competitive with the single exception of the capacity market in the PJM West region, which we noted last year as well, with PJM folded into the overall capacity market in June of 2003, therefore, removing that as an issue.

(Slide.)

On the next slide, it simply presents an issue which is frequently of concern and that is the level in which it transacts on the daily stock market. For PJM, that number is about 40 percent in 2003. That simply means, in a voluntary spot market like PJM where entities have the ability to engage in transactions of multiple types bilateral transactions, contract for differences, et cetera, those participants are comfortable, in fact, see benefit in using the PJM spot market.

(Slide.)

The next slide shows the supply and demand fundamentals for PJM in 2003. Basically, what it illustrates is that the supply of capacity has shifted out. No economists, only David, managed not to present a supply and demand curve. The supply shifted out by about 5000 megawatts of gas-fired capacity. Demand was actually lower in 2003 than it had been in 2002. The fundamental for such that there's overall downward pressure on prices.

(Slide.)

Despite that, if you go to Slide 6, overall prices were up as they were in New York. Actually, I think they were up a bit more in PJM. They're up by 35 percent, pure and nominal non-load rated basis. On a load rated basis, which is the way that load pays for their power, it was up about 30 percent in 2003 over 2002. But, as in New York, what was driving that was fuel prices. That's what you would expect in a competitive market. When fuel prices goes up, the price of the market goes up as well. When we made an explicit adjustment to index the price increases for fuel cost increases for every marginal unit in every five-minute period, prices were actually lower in 2003 by about 10 percent after accounting for fuel costs. That's not what people paid. People really paid the 35 percent or 30 percent increase. Nonetheless, that was a result of input price costs, not the exercise of market power or any non-competitive behavior.

(Slide.)

The next set of slides I won't tell you about in much detail. They simply illustrate that gas prices were higher and that the predominate part of the price increase in 2003 over 2002 occurred in the first quarter of 2003 when the gas price differential was at its maximum.

(Slide.)

Slide 11 illustrates the fact that there were more gas-fired units on the market in 2003 than in 2002. That is, gas was setting price, setting the L&P in PJM more frequently in 2003 than in 2002.

(Slide.)

Slide 13 shows the price duration curve, exactly the same format. We're trying to give you the same format on some graphs and the price duration curve illustrates that, as a general matter, prices were significantly lower in 2003 than they were in 2002.

Put a different way, the left-hand part of the price duration curve indicates that there were fewer instances of higher prices. Prices didn't get above $200 in 2003 at all, whereas they reached much higher levels in prior years. That was a result of those supply/demand fundamentals. Even though we moved up the supply curve, as a result of gas cost, in fact, demand was never very high in PJM compared to historical peaks. As a result, overall prices were relatively low and peak prices never got very high.

(Slide.)

The next slide is another aspect of that slide, which is the load duration curve. Again, one has to be careful in interpreting these from PJM because 2003 included 100 percent; that is, 12 months of APS, PJM West. Whereas, 2001 included APS for only three quarters. Nonetheless, what this illustrates is that when a load was overall higher, peak loads were lower in 2003 than they have been in prior years, again, contributing to the fundamentals.

(Slide.)

Slide 15 shows the impact of both LMP as well as the other components of price on the average all-in market price. Again, as you can see from this Slide 15, the average all-in market prices dominated by the LMP, and, in fact, what this is using is the low weighted average LMP across the system. In addition, the capacity cost, ancillary service cost and operating reserves are uplift costs.

(Slide.)

Slide 16 illustrates the fact that day ahead and real time prices were about 35 cents apart in 2003. They'd been very close since the day the market was introduced. In fact, even hour by hour, which is somewhat unusual.

CHAIRMAN WOOD: That's what was introduced?

MR. BOWRING: The day ahead market.

CHAIRMAN WOOD: Is there much virtual trading going on?

MR. BOWRING: Yes. In fact, we have virtual trading virtually at every bus. It's allowed at every bus. It's hard to believe. It's only zonal in New York. That is essential to driving those prices together. When traders see that difference, they take advantage of it and arbitrage the price differences. We should expect it to happen.

CHAIRMAN WOOD: Back to the prior one, 15, capacity costs have gotten tighter and tighter. Has there been increased construction in PJM?

MR. BOWRING: I'd like to talk about the exact capacity prices in more detail in a moment. But the capacity prices are lower because, at least, last year the market was fairly long, again, reflecting the fundamentals in the capacity market.

(Slide.)

Slide 17 is a direct measure of what one part of market structure HHI.

COMMISSIONER KELLY: Joe, was the discrepancy between day ahead and real time of concern?

MR. BOWRING: No. It's virtually zero. As a matter of fact, there maybe a bit more risk in the day ahead than in real time because both generators and loads are taking a certain amount of risk in day ahead.

COMMISSIONER KELLY: So 35 cent is close enough?

MR. BOWRING: Yes.

COMMISSIONER KELLY: Thanks.

MR. BOWRING: Slide 17 is one measure of market structure to which your staff referred earlier in the day.

It's the HHI measure. It's a gross measure. It doesn't show everything about a market. But, nonetheless, it's relevant and gives an indication of what the structure looks like in an energy market measured on an hourly basis. Taking explicit account of the exact ownership of inputs and exports, HHI was at a maximum of about 1600 and a minimum of about 950 in 2003. It averaged around 1200, which is in the moderate range. Again, it's not reason to believe that there could not be the exercise of market power. But, given other mitigating factors in the market design and market behavior in PJM, it's consistent with a competitive outcome.

By contrast -- I don't have a slide on this, but there is detailed information on this in the State of the Market report. By contrast, to the overall market, local market HHIs are extremely high. If you look just at some particular ones, Public Service North, for example, has an HHI of about 6500. Public Service North Central has an HHI in excess of 7000. The Delmarva Peninsula has an HHI in the vicinity of 5000.

So there are a number of key areas in the list, specifically, in the State of the Market report where there are issues of potential and actual, in some cases, local market power. And, in that case, the local HHI is a very indicator that there is a local, structural problem. That structural problem is defined by transmission constraints that occur from time to time and the exact details of that are set forth in the report.

Another overall measure of concern about potential market power is the RSI index. That's presented on Slide 18.

(Slide.)

MR. BOWRING: What this measures is the extent -- well, it measures what your staff has referred to earlier as pivotal. Pivotality, I don't know if that's a word or not. It doesn't sound like a word, so I'll stop saying it now.

(Laughter.)

MR. BOWRING: The extent to which they are pivotal, all that means is, at the margin, if you're pivotal, you are a monopoly. Your output is needed to clear the market. If you're pivotal, you're a monopoly.

The simplest test of being pivotal is when the RSI is less than 1.0. If the RSI is less than 1.0 for an hour, there is someone in that hour who's pivotal who has an monopoly position on the margin. It doesn't mean they exercise market power, but, again, it's a screen to see if we need to look more deeply.

The final aggregate test we look at for kind of gross indications of market power is Slide 19. That's the markup index, the difference between price and cost divided by cost.

(Slide.)

MR. BOWRING: Although it gets a little more complicated in implementing it, PJM, unlike, I think, most other RTOs requires every pre-1996 unit to submit a cost curve every day as well as their price curve. So we have their cost. We check their costs but we have cost submitted by the companies themselves. What they believe to be their actual cost, including a markup over what we've defined in a (inaudible) precise way, including a markup of 10 percent over that cost.

COMMISSIONER KELLY: Joe, how do you know that the cost data that's submitted to you is accurate?

MR. BOWRING: We check it in a number of ways. We check it against historical data. We have data going back through times when generators submitted their data only on a cost basis.

As far as the fuel cost component, which is really the largest component, we look at a number of measures. The Commission approved our access to something called e-fuel. Our application is called e-fuel. We actually get monthly fuel cost data from the generators directly. We also look at a number of market measures. We look at cost in gas, coal, oil, and so forth, and we also do comparison across units of similar types. I have generation experts on my staff and we also use consultants. So we come at it in a number of different ways and we are confident that the costs are, in fact, generally correct. From time to time, we identify units that don't appear to be submitting the correct costs. Usually, they've simply failed to update and correct it. So I think we have a pretty good handle on that.

COMMISSIONER KELLY: Thanks.

MR. BOWRING: The actual markup in 2003 over cost, plus 10 percent, averaged about 3 percent. And it has, over the years, averaged in the 2 or 3 percent range. If you assume that the 10 percent is part of the markup, then that markup rises to 12 percent. I think the truth lies somewhere in between. I think there are elements of actual marginal costs that are probably not included in our definition. We're, in fact, working on that through one of the PJM stakeholder groups. But, all in all, the three overall gross measures of at least the ability to exercise market power, the structure and behavior indices indicate or are consistent with the conclusion that PJM energy markets had competitive results in 2003.

(Slide.)

MR. BOWRING: The capacity market is set forth. Some results for the capacity market are set forth in Slides 20 and 21. The essential point there we are, as I indicated before, relatively long in 2003, about 1000 megawatts or so long in 2003 when you compare the load obligation to the installed capacity and the forced outage rates. That is, the unforced capacity which PJM uses as well.

But, finally, Mr. Chairman, to come back to your question on Slide 22.

(Slide.)

MR. BOWRING: This illustrates the prices for capacity. It's a somewhat busy chart. The blue curve indicates the monthly and multi-monthly prices for capacity since the beginning of 2000. As you can see, it rose somewhat in 2001, but it has declined fairly steadily since then. That, in fact, is consistent with the underlying fundamentals. We've been long by an excess of 1000 megawatts.

The other thing to remember about the daily prices is that there are very few megawatts that have cleared that daily price. It's a balancing market. Those who use it, use it at their own risk on both the supply and demand sides.

That price actually averages very close to zero for around the last year and a half. That reflects the actual marginal cost of capacity on a daily basis, which is very close to zero and reflects the fact that there is excess supply for that market.

The daily market can be, as you can see, somewhat more volatile in the monthly market. Now, the next slide wraps it all up.

(Slide.)

MR. BOWRING: It talks about net revenue. There's actually some much more detailed data in the State of the Market Report itself.

The key fact here, in 2003, is that in 2003, in PJM, net revenues from a new combustion turbine were down quite significantly over 2002, which is, in turn, down significantly from 2001. Total net revenues in 2003 were about $25,000 a megawatt year.

Again, depending on how you calculate them, we calculate the costs for a new CT, 100 percent of carrying costs, and all costs in PJM in 2003 would be in the high

60s, about $68,000. That's not a magic number.

One of the things that we're working with, with both your Staff and the other ISO market monitoring units, is to just make all the assumptions underlying those numbers, explicit, so everyone can understand why they are different. We should have something for you on that, probably by midyear of this year.

But, again, the essential point is that this is a measure of one, again, gross measure of the overall results, the overall competitiveness of the results of the markets. What this suggests, overall, since 1999, is that, on average, a new CT would have just under-recovered its total cost. It would have made a rate of return that would have covered its costs, but not quite the rate of return built into the $68,000 number.

With combined cycle, that's also the case, although slightly less so. There are detailed numbers in the report on combined cycles. This not only gives an indication of the overall competitiveness of the market, but also the incentives for a new unit to enter.

Clearly, if a new unit thinking about entering PJM markets right now, thought that 2003 was going to be repeated forever, clearly, they wouldn't enter, but it's also the case that the markets are cyclical.

I'll show you in a moment that the queues are down and it's clearly the case that the markets will turn; it's just a question of when it will turn around. Prices will rise, incentives will change. Slide 24.

(Slide.)

MR. BOWRING: This shows the forced outage rates on an annual basis. The force outage rate in 2003 was up a little bit, from a little over five to a little over seven percent.

We know the exact details of why that is, that is, we know the contribution to that increase on a unit-by-unit basis. We're confident it's not physical withholding. We're confident that the units and the owners of the units -- this is the case for it -- did not have an incentive to physically withhold. Things happen to units, as your engineers can tell you, and they break down, and that was more the case in 2003 than it had been in some prior years.

(Slide.)

MR. BOWRING: Slide 25 shows the queues I was referring to. It shows about 5,000 megawatts are in queue to be installed in PJM in 2004 and 2005. Those queue sizes drop off fairly significantly after that, beginning in 2006. Again, that's reflective of the people's current expectations about prices in PJM.

Investors, as we know, have been somewhat shortsighted, both over-investing, and, at times, under-investing, but that's how markets work. Markets are messy, and relying on markets to invest in new capacity, doesn't always work as it did under regulation.

MR. HEDERMAN: I notice in the queue -- could you characterize the type of units?

MR. BOWRING: Yes. In fact, coal-fired units, inframarginal coal-fired units did very well in 2003, even though the spark spread for a gas unit was virtually zero, for a coal unit which is operating at a much lower cost, because the coal costs did not go up anything like they did for oil and natural gas, there were very nice inframarginal rents to be made. Most of those units did very well, as did nuclear units. Anyone who was running inframarginally, whose fuel costs did not go up, did well.

There's been a certain amount of interest in the way in which we do our local market power mitigation in PJM, so I included slides, Slide 26 and 27.

(Slide.)

MR. BOWRING: Slide 26, to begin with, on the number of units that are offer capped in real time. What this shows is -- this is the unit hours. It's the average number of units which are cost-capped in a particular hour. The significance of this, among other things, is that first of all, total unit hours cost cap went down. It fell by about 50 percent between 2001 and 2003.

Some of the reasons they were higher in earlier years, had specifically to do with the Delmarva Peninsula and transmission upgrades specifically designed to avoid having to cost-cap. In fact, with the data for 2003 and also for the first three months of 2004, what the data indicates is that that's been successful and the offer capping has been significantly reduced.

Another take on that is the percent of real-time offer cap megawatts by month. Again, that's average. The average is clearly down from 2001 to 2003. It's about one percent overall in 2003.

The other point that I make in the report about offer-capping is that despite the intuition about it, offer-capping, in fact, cannot be shown to have a negative effect on the net revenues of real combustion turbines.

(Slide.)

MR. BOWRING: On Slide 28, there is just general information about imports and exports. PJM is a net importer in every month. In fact, the flows tended to come from the West. We import from the West, from AEP, ECAR, and so forth, and we export to New York, although more comes in from us than goes out to New York, so we are, in general, a net importer.

COMMISSIONER KELLY: If AEP and Commonwealth Edison were to join you, how is that going to change this?

MR. BOWRING: That's a very interesting question. When

APS joined us, when PJM West joined us, what used to show up as imports showed up as internal. It resulted in a much more efficient dispatch of those units. There was actually more congestion as a result, but the imports simply shifted further West.

We still had significant imports. Commonwealth Edison, for example, still has significant interfaces with the rest of the world and will still see imports, although Commonwealth Edison, 99 percent of the time, is an exporter. Commonwealth Edison has a lot of inexpensive nuclear and coal generation. They tend to export; they tend not to import.

AEP, if and when AEP joins -- or, I should say, when AEP joins on October 1st, we expect them -- again, it will be the same effect. There is a lot, as we know, of coal-fired generation in AEP, which is not showing up as an import. That would then be internal.

COMMISSIONER KELLY: So the imports -- bottom line is, imports will decrease or not?

MR. BOWRING: I don't think it's possible to say that. We're simply going to shift the borders out and have a different set of borders. The MISO markets are up and running and we'll have a set of borders with the MISO markets. I think there will still be imports.

I haven't evaluated what we expect from net imports when AEP and Commonwealth Edison enter the grid. Slide 29.

(Slide.)

MR. BOWRING: This just presents a simple picture of congestion. What is shows is the difference between the PJM West hub, which is a good overall measure of the price overall in PJM, the difference between that in each zone in PJM. As you can see, what it shows is that as a general matter, zonal congestion has declined, zone-by-zone.

In significant part in 2002, that was a result of the addition of APS. Instead of having to import and to have to have higher prices to attract the imports, you simply have more efficiently redispatch. The exceptions to that were Public Service Electric and Gas in northern New Jersey and the PECO areas where there were some identifiable transmission issues that resulted in higher zone-specific congestion.

Finally, in 2003, PJM modified the way in which it deals with FTRs, very significantly. Instead of having FTRs be directly assigned to loads, we switched to assigning auction revenue rights or ARRs, which are valued based on auctions for the underlying FTRs. That process worked very well.

Holders of ARRs are permitted to self-schedule FTRs, so if they prefer not to rely on what they think the market price will be of FTRs, they can self-schedule. Almost half of the ARRs were self-scheduled.

The overall result in 2003 is that FTRs served to hedge about 96 percent of actual congestion costs, and those who chose ARRs and also self-scheduled, their total portfolio served to hedge about 89 percent of overall congestion costs and you can see that the biggest difference is in revenues between total congestion and actual hedge, where, again, in PECO and Public Service Electric and Gas, again, because of congestion, in this case, because of unanticipated congestion. That completes the slides.

CHAIRMAN WOOD: Go over that last slide again.

MR. BOWRING: The blue lines are the ARR credits, directly. If I'm an ARR holder, I have both of those ARR credits and also self-scheduled FTR target allocations, which are the orange.

I have 100 megawatts of FTRs and I decide to hold 50 as ARRs, but to effectively take direct assignment underlying the FTRs for 50 percent of them or 50 megawatts, the total revenue that I receive, total congestion revenues that I receive is the gray bar. The line is the total amount of congestion.

So, to the extent to which there is a vertical difference between the line that is total congestion and the gray bar that is the actual hedge loads in those areas, are under-hedged. If the gray bar is higher, as it is for

Pepco, loads in those areas are over-hedged.

CHAIRMAN WOOD: The two on the right would be under-hedged, just because, you said, of unexpected congestion?

MR. BOWRING: There was both an increase in congestion as a result of unanticipated changes in the transmission system. There were some transmission lines out and, of course, the details are in the State of the Market Report.

It's also the case that there are other ways to hedge one's load. If you hold generation, that's another way of hedging your load.

This doesn't mean that load was literally unprotected by Public Service; it does mean, however, that the combination of FTRs and ARRs did not hedge in those areas, 100 percent of their condition costs.

CHAIRMAN WOOD: Considering the maturity of your market, what would you say are the structural problems that remain?

MR. BOWRING: I would say that the primary one we're looking at is the capacity market, and while I don't think the capacity market is a disaster, I think that the capacity market needs some careful rethinking. I think that PJM is committed to actually taking the lead on that.

One of the things which David suggested was locational capacity. We've discussed that in the context of our local market power option. I do agree that there are significant differences on locational capacity values.

The difficulty with the capacity market is, as I have said repeatedly, that I think market power is endemic to the capacity market. It's basically structured to never be long, to almost always be tight.

When that's the case, you typically have pivotal suppliers. I think there are some straightforward ways to design a capacity market such that you have built in, market power mitigation, ex ante, clear ex ante mitigation. Everyone understands it, such that, effectively, in the case of locational capacity, you could have a demand curve and a supply curve, such that you don't let people take advantage of the fact that locational markets are much smaller than the overall. So, if you have market power in the overall market, you're likely to have much more market power in smaller markets.

It is appropriate, I think, to reflect the local value of capacity. Capacity in PJM is probably worth more right now than it is in the West. Our capacity market doesn't allow us to reflect that. I think it should.

That's one of several key features we're talking about inside PJM and PJM is talking about building into a revised capacity market redesign.

CHAIRMAN WOOD: Would you say that there would be a consensus developing around that type of proposal?

MR. BOWRING: I don't think of it as a local capacity market, so much as I think of it as redesigning the entire market to take account of certain important features of capacity, one of which is location. I think there could.

What PJM is planning to do is to take the lead and develop the model, and then build consensus with the members; that's our goal.

CHAIRMAN WOOD: How can you all integrate that effort with that of the New York and New England ISOs? Isn't New England kind of pushing on that, since I've been here, towards a kind of regional approach to capacity markets?

MR. BOWRING: In our effects on the regional markets right now, New York is buying a significant amount of capacity from PJM. I'm not sure what the process is between New York and New England.

We have been trying to come up with a design that can work across all RTOs. That was -- I think RTO is now pulling back a little bit and making sure that they can build a consensus on aspects of that within the individual RTOs, and then we'll probably try to re-integrate.

I think everyone is moving generally in a similar direction. Whether it's identical or not, ultimately I don't know, but we certainly agree that that's an appropriate goal to try to do that.

CHAIRMAN WOOD: There are pending decisions shortly on

New England. I just want to make sure that if there's a different way things are going in PJM --

MR. BOWRING: I think the proposal -- I mean, there still has to be a capacity market. That's the way in which we monetize reliability, at least in the East. It's a question of making it a little bit more sophisticated so we can take account of generation and other attributes of capacity.

I think that's consistent with what New England is talking about.

CHAIRMAN WOOD: For both of you, looking at and thinking about the New York market, in particular, I don't want to get too close to the pending case with your stuff, but the concept is similar. I wonder, do the mitigations that are in place for the more constrained areas, properly attribute some sort of value to the fact that they have added reliability to the system by being, I guess, either contributing reactive power voltage of just real power where you need it? And they can't otherwise get it due to constraints?

MR. BOWRING: Let me take a stab at that first. In PJM's load pockets, typically we're actually not short of capacity. We're typically long. The issue really is a structural issue.

As David said about New York, if you require divestiture of units or require a different ownership structure, then load pockets -- our amount of offer capping would decrease significantly.

One of our key load pockets only has one pivotal supplier. They own generation that is offer-capped on a regular basis, not because we're short, but because there's only one owner of the capacity that's needed to keep the system reliable.

I think that, in some sense, all generating units are required to keep the system reliable. That's why we pay overall capacity payments.

When we actually get to a point where there's scarcity -- and, again, I don't want to get too close to anything -- when we actually get to a situation where there's scarcity, we recognize that there has to be a different kind of mechanism to do, as you said, to value that.

If you need incremental capacity in your load pocket, you have to pay for it in such a way that it's an incentive for someone to relocate there, and our goal is to find a market mechanism to get that incentive.

MR. PATTON: I think this is one of the most critical issues facing any of these markets. I thought the discussion we had at the technical conference was excellent.

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To sort of review what my position was and is on this point, I think that you have a series of choices on what to do to reflect the reliability value that units in these load pockets are providing to you. And that reliability value is very unique. You're not, by and large, resolving thermal constraints, which is the normal, what you'd expect to cause LMP price differences.

You're meeting local reserve requirements. In the major load centers like Boston and New York City, they're actually meeting a higher reliability standard as a second contingency so that they can sustain their largest contingency and their second contingency.

In the commitment process, they have to turn out a lot of generation to meet this requirement. They then don't see the locational prices, so then the question is, how do you reflect how much value these things have? The operators in these areas will say we can't lose any of these units in these areas; we need all this capacity to maintain reliability.

The first, best way of doing it, from a theoretical standpoint, is to have your operating reserve markets reflect locational requirements. Those markets operate on an hour-to-hour, day-to-day basis, which is the same timeframe as the operators are trying to hold this reserve in these areas.

When you do that, it creates a signal, because if it can't meet that requirement, if you place an economic value on it, you're going to get shortage pricing. That's what we're going to be doing and what you've approved for New York, marketwide, reflecting when we're short, marketwide, we're not doing it for New York City, yet the second way to do it is locational capacity requirements, which are really more of a proxy for that requirement over a longer-term basis, so it creates substantial incremental value for those resources.

When we start talking about mitigation and how does mitigation affect these incentives, in my mind, the discussion we're really having is, if we don't provide the incentives through these preferred means, or, in my opinion, the preferred means, then we're left with the choice of saying, well, let's allow people to exercise some reasonable amount of market power to get a signal that we think is relatively efficient. To me, you only turn to that step if you have decided you can't do one of these other steps for some reason.

In New York, the mitigation, I think, is effective. It's relatively tight compared to what's been proposed for some load pockets in other places, and, largely, it's reasonable because of the locational capacity dimension of the market.

If you took that away, I think you'd have to rethink how the mitigation works.

It's very difficult to try to produce that signal, as you saw with the push provisions in New England by just loosening the mitigation, because you don't know what you'll get; whether you get signals that are too high and unjustified or too low and still don't solve the problem.

CHAIRMAN WOOD: You said, "yet," a moment ago. Are you thinking about a demand curve in New York City only? MR. PATTON: I haven't proposed that. The problem with scarcity pricing is that you have no control over it, really. If you're short and there's a tradeoff being made between your reserve market and your energy market, and there's a value you've placed on that, if we're short in New York City a thousand dollars, you're going to be at $800 and $1,000 prices, and that's the end of deregulation in New York.

So, the locational capacity -- one problem is, by implementing that overnight, you're looking at a legacy of investment that's gotten you to a certain point, and to just flip that switch at one point in time, is a fairly extreme measure, so locational capacity is a much more measured approach toward getting those signals set.

CHAIRMAN WOOD: We talked about virtual regional dispatch on the New York-New England scene, and I know y'all are working on the same thing with MISO. What about between these two markets here? Is there some value to be gained by doing a joint dispatch across that seam?

MR. BOWRING: We looked at that specifically in the State of the Market. One of the things we looked at was the extent to which the price differences actually do reflect the underlying fundamentals. We think they do reflect the fundamentals, but it's very much refracted through the prism of existing rules that impose risks which make it very difficult to have purely efficient transactions on an energy price basis between PJM and New York.

So, while the mean difference is very small, 35 cents or something like that, the variance is huge. There are a lot of fluctuations around it, driven by the rules.

What we've recommended -- and I think it's the right thing to do, is to do something similar to what we do with MISO, to have joint redispatch for congestion between PJM and New York. Probably the best way to handle that is to let that go forward with MISO.

David and I talked about this a little bit before, to let that go forward with MISO, to work the kinks out, make sure it works, and then apply it to New York. It's absolutely the right way to go, to do joint redispatch on both of these systems. It would resolve a lot of the loop flow and other issues there.

CHAIRMAN WOOD: Thoughts for Joe and David or Steve?

(No response.)

CHAIRMAN WOOD: We're always glad to see you. Thank you for your presentations. We will conclude the open meeting and have the closed meeting at 2:35 on the third floor.

(Whereupon, at 2:10 p.m., the open session was concluded.)