BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

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886TH COMMISSION MEETING

OPEN MEETING

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

Wednesday, April 13, 2005
10:10 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

SECRETARY MAGALIE R. SALAS

ALSO PRESENT:

JANE W. BEACH, 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 items which have been posted for this time and place. Let's start with the Pledge to our Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Before we start, I want to call attention to two personnel items in the Commissioners' Offices. One is that we've had a half-century milestone passed by one of our illustrious male assistants to the senior female Commissioner of the Agency. He will be unnamed.

(Laughter.)

CHAIRMAN WOOD: And I also want to welcome to my personal staff, Derrick Bandera, who has joined us, joined Mark and Dion and Jason on the staff working for me. So, I want to thank OMTR for letting him go, and also welcome Derrick up to work with me.

Madam Secretary, I know you have some interesting things going on that you want to tell the world about.

SECRETARY SALAS: Yes, but first of all, good morning, Mr. Chairman, and good morning, Commissioners. I would like to announce that later this week, the Office of the Secretary will be issuing a notice, announcing the new manner in which the Commission will begin to issue Notices of Filings.

This new method will apply initially only to electric rate filings, and it is our expectation that, gradually, the Commission will issue the majority of the Notices of Filings using this method.

By this initiative, we seek to simplify the manner in which the Commission Staff prepares notices, so that we can expedite the issuance of notices to the public.

Essentially what we will do is, we will work with a group of filings incorporated into E-Library the previous day, and then select all identifying details for each filing. These details include: Docket Number, applicant's name, filing date, a brief description of the filing, comment date, and the E-Library accession number and the link to the filing.

We will then include each set of identifying details in one document that will list between 10 and 15 filings. And if our Staff is ready, I would like to show you, very briefly, what the document will look like.

(Slide.)

SECRETARY SALAS: And there is it. Thank you very much.

A short name for this document is Super Notice, because it is packed with information and it's one-stop shopping for the particular group of electric rate filings. The Super Notice is very similar, I will note, to the electric rate group notices that the Commission has been publishing in the Federal Register for the past ten or more years.

We will begin generating these Super Notices in the last week of April, and as I mentioned earlier, we will include this information in a notice to be issued later.

Finally, I want to thank the Executive Director's Staff for their support and hard work on this project, and, in particular, Brian Starkey and Alisa Faraday, who are sitting right there in the corner of the first row. Thank you.

CHAIRMAN WOOD: Is that it?

SECRETARY SALAS: Yes.

CHAIRMAN WOOD: Thanks. We look forward to the efficiency improvements, and I know your staff has been working hard to make them happen.

SECRETARY SALAS: Now we will do your Consent Agenda for this morning. First of all, I would like to announce the items that have been stricken from the agenda since the issuance of the Sunshine Notice on April 6th.

They are: E-7, E-21, E-26, E-42, E-59, E-87, E-88, H-3, H-7, and C-10.

Consent items are: Electric - E-6, E-9, E-10, E-

11, 12, 13, 15, 16, 17, 19, 20, 22, 23, 24, 27, 28, 30, 31, 33, 34, 35, 36, 37, 38, 39, 40, 41, 43, 44, 46, 47, 48, 49, 50, 51, 52, 53, 56, 58, 60, 61, 66, 67, 68, 69, 70, 71, 72, 76, 77, 78, 81, 82, 83, 85, and 86.

Miscellaneous Items: M-1.

Gas: G-2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 13, and 15.

Hydro Items: H-1, 4, 5, 8, and 9.

Certificates: C-2, 3, 8, 9, and 11.

And these should all be on the screen, except for E-35, which is the last addition to the Consent Agenda.

As required by law, Commissioner Kelly is recused from the following items on the Consent Agenda: E-9, E-31, E-51, E-72, E-83, and H-8.

Chairman Wood is recused from E-71.

Specific votes for some of the items on the Consent Agenda are as follows: E-53, Commissioner Kelly dissenting, in part, with a separate statement; E-71, Commissioner Brownell dissenting, in part, with a separate statement; E-78, Commissioner Kelliher dissenting, in part, with a separate statement; G-2, Commissioner Brownell concurring, with a separate statement; G-13, Commissioner Kelly concurring, with a separate statement; H-8, Commissioner Kelliher concurring, with a separate statement; C-2, Commissioner Brownell dissenting, with a separate statement; C-11, Commissioner Brownell dissenting, with a separate statement, and Chairman Wood will be writing separately on H-8.

And now Commissioner Kelly votes first.

COMMISSIONER KELLY: Aye, with the exception of E-53, noting my partial dissent, and noting my concurrence in G-13.

COMMISSIONER BROWNELL: Aye, noting my dissent, in part, on E-71, my concurrence on G-2, and dissents on C-2 and C-11.

COMMISSIONER KELLIHER: Aye, noting my concurrence on H-8 and my partial dissent on E-78.

CHAIRMAN WOOD: Aye, with my recusal, as noted, due to the Texas PUC. Some of cases never leave.

SECRETARY SALAS: Okay, now, the first item for discussion --

CHAIRMAN WOOD: Just a second. I want to mention a couple of things about those items there, because we did do a lot over the past cycle, and I wanted to call attention to those things. That's why we didn't call they separate; were items that we had voted on just now.

A couple deal with market-based rate developments. One item here is a rejection of unrelated tariff provisions that are outside the scope of compliance.

In E-24 and E-39, the filing utilities included several changes to their market-based rate tariffs, revisions to the code of conduct, affiliate sales prohibitions, et cetera, that were actually outside the scope of what we had previously directed in compliance.

So this is the first instance in the whole series of market-based rate filings that we've been going through the past several months, that we want to kind of call attention about new precedent being set here, that market-based rate revisions that are beyond the scope of Commission directed compliance, should be filed as a separate 205, and, in this case, would automatically be deemed rejected, as we did here.

Another one, another instance that's interesting here in the market-based rate package today, is the issue that we talk about with the indicative screens. They are not definitive; we've said that.

Here, we actually follow through on that. Some of the industry were concerned that, notwithstanding the earlier statements, if a company fails the indicative screens and a Section 206 is begun, then the final decision has been made and that the market-based rate is going to be revoked or somehow curtailed, in E-41, for Puget Sound, the Order terminates a 206 proceeding and finds that Puget, in fact, did satisfy our market powers' concerns.

Back around Christmastime, we issued a Section

206 against Puget, and set their rates for hearing, subject to refund, because the market power study remained deficient after several attempts to correct the problems.

They have corrected those problems, and so this proceeding is the first one in which we have acted on the 206 that we began on an earlier date.

So, I hope that people will take that as proof that the Commission is being consistent with what we've said.

E-9, which was consented, approves a settlement with Mirant. It's a global settlement in the truest sense of the word, which encompasses the California refund proceeding, as well as the issue of Mirant's compensation for reliability must-run generation and a potential asset sale by Mirant to PG&E and certain unfinished generating facilities.

Under the settlement, a total of approximately $458 million will be assigned by Mirant to the California Parties. This excludes an additional $37 million issue relating to some California PX-retained funds.

These will be used to make refunds to market participants, according to the allocation matrix which we've set up in the master docket. Including today's action, the Commission has now accepted or helped bring about $4.7 billion in monetary settlements in the wake of the Western energy crisis.

And I would also like to announce that the Commission has created a comprehensive document detailing the Commission's actions, starting back in '99 and 2000 in response to the Western energy crisis and the Enron bankruptcy, and this document will now be made available on our website.

And, finally, we had a package of seven Orders relating to rehearing requests and compliance filings on the launch of MISO's energy markets. Specifically, we addressed revisions to the MISO's transmission and energy markets tariff and issues related to the treatment of grandfathered agreements.

Overall, we upheld the vast majority of the terminations made in previous orders and dealing with the Commission's implementation of the MISO energy market. We also ordered several additional compliance filings to ensure increased system reliability and competition in this broad region that extends from Eastern Montana through the upper Midwest, and South to parts of Kentucky, Missouri, and over to Ohio.

We will continue to monitor the implementation of the MISO's energy market to ensure protections for wholesale customers.

Sudeen and I had the pleasure of representing the

Commission at the midnight cut-over back on March 31, April 1, over in the Carmel offices there, and we were real pleased to be part of that. I know we'll hear a little bit about that from the market monitor later this morning, but it was nice to be there.

Our two guys in the office out there have been very involved in addressing the customer and reliability issues, working with MISO and communicating back to us and to Commission Staff, as well. The OMOI folks have been very involved, as well, with the market startup issues with the market monitor and the team over at MISO.

So, I want to tip my hat to the fine work that the MISO leadership and the market participants have done to get that market to the point where it is, and look forward to delving deeper into some of the benefits and challenges ahead, as we talk with Mr. Patton later this morning.

So, I think that's all we've got in the packet of consent items, and I thank y'all for letting me call attention to some of that. All, right --

SECRETARY SALAS: Okay, the first item for discussion is A-3. This is State of Markets Presentation, and it is a presentation by Mr. Joe Browning from PJM and Mr. David Patton from MISO.

MR. HEDERMAN: Madam Secretary, it's Joe Bowring.

SECRETARY SALAS: Oh, Bowring, thank you. That's still you.

(Pause.)

CHAIRMAN WOOD: Well, welcome back, Joe; we'll start with you.

MR. BOWRING: Thank you, and thanks for the opportunity to be here. The 2004 State of the Market Report, as it exists in its full physical glory, published on March 8th, is 350 pages, and we were trying to cut back.

Our basic conclusions were that the energy market results in PJM, including all three phases of the energy market, including the integrations, energy market results were competitive; the capacity market results were competitive, with the exception of, in ComEd, we couldn't find that the capacity market results were competitive, although we found that they were reasonably competitive, and what we meant by that was that the prices in those markets were less than what we had set previously as a benchmark for a reasonable outcome of $30 a megawatt day.

The regulation market results in PJM and the various submarkets of PJM, were competitive. It's worth drawing attention to the fact that regulation markets only in PJM Mid-Atlantic, were price-based; elsewhere, they were cost-based.

So, the conclusion that they were competitive when they were cost-based, is less meaningful, of course, than when they were market-based.

The same thing is true for the spinning market results. Spinning markets in PJM continue to be cost-based, because of structural issues in those markets, and those results, we found, were competitive, as well.

And, finally, the same is true of the FTR markets.

Our more general conclusions were that market power in the capacity market, continues to be a persistent issue, as measured by various structural measures -- high concentration, single pivotal suppliers, inelastic demand.

And we conclude that basically any new market design has to very explicitly address that market power issue.

In addition, we concluded that the ancillary service markets, in general, in PJM, are not yet structurally competitive, and that cost-based rates should remain in effect until such time as we can demonstrate that the structural conditions for competition exist.

Our basic recommendations follow those conclusions. The first is that -- and, not surprisingly, given everything else that's happened -- is that a capacity market redesign is warranted, in order to ensure that, first of all, the capacity market is competitive, clearly; that they incorporate a locational feature, and that the incorporate explicit market power mitigation rules.

COMMISSIONER KELLY: Joe?

MR. BOWRING: Yes?

COMMISSIONER KELLY: Is that the reason that you conclude that the capacity market was reasonably competitive? Is that why you put that adjective in there, because there is some exercise of market power?

MR. BOWRING: Actually, for PJM, as a whole, we said the results were competitive. For ComEd, we couldn't draw the conclusion that they were competitive, simply because there clearly were dramatic structural issues there.

But, nonetheless, the prices were less than what we had set as a maximum level, so we said "reasonably" there, although we couldn't conclude they were absolutely competitive.

COMMISSIONER KELLY: I see.

CHAIRMAN WOOD: Does that persist, or was that just for the period of time before AEP got in there?

MR. BOWRING: Right, it's -- the capacity market in ComEd won't be fully integrated into the PJM capacity market until June 1st of 2005, but the issues are primarily behind us.

There are ongoing auctions, but we're seeing results consistent with what we had seen previously.

COMMISSIONER KELLY: And what measures are in place to ensure that there's no harm done, given the presence of market power?

MR. BOWRING: In the ComEd capacity market, there are no measures, other than regulatory scrutiny. My belief is that because of your oversight and our oversight, and the fact that we sort of set as a benchmark ahead of time, that $30 was where we thought there would be an issue, that, in fact, market participants have chosen to typically offer less than $30, not because they have to and not because the structure of the market requires that, but simply because they know that people are watching.

COMMISSIONER KELLY: Thank you.

MR. BOWRING: But also, I mean, those questions draw out an important point, which is that we distinguish between the market structure -- and there may be uncompetitive market structures or market structures which are not perfectly competitive, which, nonetheless, are consistent with, ultimately, a competitive outcome.

So, while our energy market structure is not perfect, we don't have an HHI to 500, nonetheless, we do seek competitive market results, and that's why we just need to continue to monitor it.

In addition, in our recommendations, we recommend modifying the PJM operating and reserve rules in a number of ways, but primarily to reduce gaming, to ensure incentives for efficient market outcomes, and also to ensure that PJM, as the market operator, is operating in the most effective and efficient way possible in using units for operating reserves.

And, finally, in the recommendations, we recommend that PJM review, modify, and clarify the rules governing outage reporting and verification, in order to ensure that we get an accurate assessment of system conditions, as well as incentives for efficient market outcomes.

I don't know if we're going through slides or not, but what I have is Slide 3. There's a map which simply shows the current configuration of PJM, with various pricing points identified.

Slide No. 4 is one that usually draws interest, and that simply shows the proportion of load being met in the spot market. And in PJM, in the real-time spot market, the share of load being met in the spot market declined from 40 percent in 2003, to 35 percent in 2004.

However, it's important not to read too much into that. As a result of the California experience, it's frequently thought that simply participating in those power markets, is an indication that one is exposed to risk, and that's clearly not the case.

We know for a fact that on the order of half of that 35 percent, is actually the result of bilateral contracts between large participants in PJM, which is simply being run through our spot market and run through our settlement system.

And rather than being an exposure to risk, in fact, it's a vote of confidence in PJM markets and in PJM settlement mechanisms.

CHAIRMAN WOOD: So, would they just actually be -- would they price it at whatever the PJM LMP would be? Is that why they would run it through that market?

MR. BOWRING: Well, although I don't know, my guess is -- and I know this in the case of some contracts -- typically, there's a contract for differences on the side of financial contracts for differences, so, while, in effect, at least at the first pass, it's being passed at the spot market, in fact, there's a financial side deal, which prices against that.

It uses the spot market as a reference price, but prices against that.

COMMISSIONER KELLY: And, Joe, what do you think of that as a mechanism in the marketplace? What I'm really asking you is, is there an advantage for this kind -- is there an advantage for consumers in this kind of a marketplace, versus a marketplace that's not organized?

MR. BOWRING: Yeah, absolutely. I mean --

COMMISSIONER KELLY: And what is that advantage?

MR. BOWRING: The clear advantage is that there is a transparent price signal which exists every five minutes and every hour, which every party can see, and which parties can then use as the basis for bilaterals. It's a frequent misunderstanding that in PJM, there are no bilaterals, that the bilateral market is weak.

In fact, the bilateral market in PJM is incredibly strong, both within PJM and also the over-the-counter bilateral market.

COMMISSIONER KELLY: When you say "bilateral market," you mean the spot and the --

MR. BOWRING: No. Actually, when I say "bilateral," I mean, party-to-party, which uses the spot market as a reference point.

COMMISSIONER KELLY: But you mean a bilateral for different types of products?

MR. BOWRING: Yes, exactly, bilateral for energy or capacity or for any of the various products. But it's essential to have an organized central market so that pricing was there and people can have confidence that it reflects the underlying efficient dispatch of the units.

Slide 5 shows the output. And we haven't show this before in this state of the State of the Market. It shows the output by fuel type in 2004, in gigawatt hours.

Actually, it surprised me a little bit. Almost 90 percent of output is baseload units between coal and nuclear; a relatively small proportion of about seven percent or so, is gas fired.

And while these don't match up identically with the capacity numbers, which are clearly quite different -- for example, we have -- about 28 percent of capacity in PJM is gas fired; only seven percent of the gigawatt hours are gas-fired.

COMMISSIONER KELLY: Do the gas-fired tend to set the price?

MR. BOWRING: Gas-fired is on the margin, about 30 percent of the time or 31 percent of the time. Interestingly, in PJM -- and, again, it always surprises me -- coal is on the margin about 55 percent of the time, which is a very high proportion of the time for baseload units.

COMMISSIONER KELLY: And how do those prices compare? Is gas higher on the margin?

MR. BOWRING: Yes, gas, as a fuel, is more expensive, and they typically have poorer heat rates, so when gas is on the margin, it means that we're in a higher-priced portion of the supply curve, absolutely.

The next slide shows the impact of the ComEd integration, as it shows the supply curves, and the supply curves shifted out to the right with the ComEd integration.

This compares to the Summer-over-Summer supply curves, and as you can see, the demand curve did not shift out quite as far.

The result was downward and moderating pressure on prices in 2004, which I'll talk about in a little bit more detail in a moment. But it was really a result of both of those factors, the supply curve shifting out and the demand curve not shifting out as much, in significant part because the weather was extraordinarily moderate in 2004.

And as you can see from Slide 7 -- and this really shows the demand. And what we tried to do was separate out the demand levels that would have existed without the integration, from those which existed with the various integrations.

And, as you can see, the demand on Slide 7, the demand is -- or the load is virtually flat in 2004 for 2003, but for the integrations. The blue curve, which goes off and upward to the right, shows the impact of integrations, so the load growth in 2004, given the weather, was almost 100 percent a result of integrations.

Slide 8 shows the monthly load-rated average prices, and what it shows is that the 2004 prices are really, on average, above prices in every prior year, but there were a couple of key things to note.

One is that there were no spikes. In 1999 and

2001, there were price spikes in the Summer months, and in 2004, prices were very flat, and in 2004, prices were sometimes higher than 2003 and sometimes less, and, again, I'll talk about that in a little more detail in a moment, but it was really very much fuel-cost-driven.

Overall, we think about price results in three ways: Simple average, load-weighted average, and fuel-cost-adjusted.

The simple average is simply taking the price in every hour, adding them up and dividing by the number of hours in a year, and, using that measure, the nominal prices increased almost 11 percent for 2004 over 2003.

On a load-weighted basis, which is probably a more accurate measure of what people actually pay, the increase was 7.5 percent, as you can see on Slide 10.

In 2004, it was lower than the un-weighted average, primarily because during the lower-priced period of the year, that is, the last quarter, we added a significant amount of load in the AEP integration.

And the final and perhaps most significant measure, but certainly a significant measure in price increases, is the fuel-cost-adjusted load-weighted price. And in this case, that price was actually down about four percent, year-over-year.

And what that reflects is what prices would have been, as best we can calculate it, in 2004, had fuel costs been exactly what they were in 2003. So, fuel costs have not gone up, and, by our measure of prices, would have gone down about four percent.

And, again, that's consistent with what you'd expect in a competitive market. Input prices are passed through in a competitive market. But for those input prices, there was actually downward pressure on the overall price level.

CHAIRMAN WOOD: So this reflects about a half-year integration of ComEd and about a sixth of the year integration --

MR. BOWRING: Three months, right.

CHAIRMAN WOOD: A fourth of a year integration of AEP.

MR. BOWRING: Correct.

CHAIRMAN WOOD: Do you have any projections of what that would be, if it were a full year reflecting the integration of those two midwestern markets?

MR. BOWRING: We've looked at it a number of different ways. It's still a decline. I mean, there are a number of ways to look at it.

We've looked it quarter-over-quarter, for example. The decline is a little bit higher, if you look at it, fourth quarter-over-fourth quarter.

CHAIRMAN WOOD: Okay.

MR. BOWRING: But, as I recall, it's about seven or eight percent, quarter-over-quarter.

COMMISSIONER KELLY: So, Joe, what is it

COMMISSIONER BROWNELL: So, Joe, what is it that the industrials, both in the Elcon Report and in the PJM -- what is it that they're talking about when they say there hasn't been value?

I'm not -- I'm confused. I haven't seen their statistics, but I think maybe we're waiting for them, but have you talked to them and do you know what they mean?

MR. BOWRING: I have had conversations with them. I'd hesitate to speak for them, but certainly one point I make to them is precisely this: That a significant part of the reason we see a 10.8 percent increase in prices, is not because there's not competition; it's not because the markets aren't working; it's because there is an increase in input prices.

And in any competitive market, you would expect that to happen, so in terms of this measure, in terms of measures of net revenue, in terms of measures of markup, which I'll talk about in a few minutes, in every one of those cases, I believe that markets have shown that they are working and that they are working effectively and they are working competitively.

CHAIRMAN WOOD: And the input prices you're referring to, are primarily the cost of coal and natural gas?

MR. BOWRING: Exactly. Coal prices, spot coal prices are up 57 percent or so, year-over-year, 2004 over 2003.

COMMISSIONER BROWNELL: Fifty-seven?

MR. BOWRING: Yes, 57 percent in spot prices, and the mix of spot and contract that's actually used in PJM, were up in the high 20-percent range, year-over-year. That was the most dramatic of all the fuel-type increases.

COMMISSIONER BROWNELL: So this report would also illustrate that the allegations that some people have made that bigger is inherently somehow more inefficient or complicated, too complicated to manage, you're just not seeing that, particularly with these integrations?

MR. BOWRING: Absolutely not. I think we're seeing the reverse. I think we're seeing a logical extension of the LMP models, so you're doing dispatch across a broader area; you're doing dispatch of units that would otherwise have to have imported across a border, subject to TLRs and the inefficiencies associated with that.

So, in fact, no. I think we're seeing the reverse. I think we're seeing that -- I mean, there's obviously a logical limit at some point. We may have reached it with Dominion, but certainly the size that we're seeing in PJM in 2004, is absolutely consistent with efficient outcomes.

COMMISSIONER BROWNELL: Thank you.

MR. BOWRING: Slide 12 shows really what I had illustrated earlier about the difference between the ComEd and the PJM markets in terms of -- this is HHIs in the energy market alone.

As you see that rain cloud looking thing over the top, it's high HHIs in the ComEd energy market. We drew that to everyone's attention ahead of time, and we had mitigation in place, should it have been necessary. In fact, it wasn't necessary. There was no price mitigation in ComEd, and the reason it wasn't necessary was really because of the pathway, the 500 megawatt or 500 megawatt maximum pathway that you're all aware of.

That did result in increased competitive pressure that had been anticipated. In fact, energy prices, overall, were competitive.

The next slide, Slide 13, is another measure of market structure of the RSI, Residual Supplier Index against the --

COMMISSIONER KELLY: Back to Slide 12, the HHI levels increased around October?

MR. BOWRING: Yes.

COMMISSIONER KELLY: Does that concern you?

MR. BOWRING: I mean, it does, in a sense. It's not so much the change, but that we're now at sort of the high moderate end of concentration.

I think that, again, the reason we look at structure and then the behavior of participants within that structure, and, finally, market outcomes, is that structure is not 100 percent derterminative of the outcomes.

So far, in PJM, and certainly in the fourth quarter, we had competitive outcomes consistent with that. This would only even be a potential issue during the very tight timeframe, during very tight demand, but, again, our aggregate supply curve doesn't give me reason for concern at this point.

I mean, it's something we're watching, but not --

CHAIRMAN WOOD: To kind of jump to may be the point there, then, in the times of tight demand, do you have the type of approved tariff language in your tariff that you administer, to address those concerns where, in fact, you do have structural -- markets that are not structurally established to be competitive?

MR. BOWRING: But for the Order that was issued a couple of days ago, which I can't claim that I totally understand, we do not. And, in fact, one of the things that distinguishes the PJM market from other markets, is that we have no mitigation, other than the $1,000 offer cap measures for the overall aggregate energy market.

As a general matter, that's worked out very well, because you have a steep upwardly-sloped portion of the supply curve, which results in high prices when you need high prices, that is, when demand is relatively high, and, in fact, that's why I indicated the shape of the aggregate supply curve is still consistent with a competitive outcome, as far as I'm concerned, because for the broad number of hours, the vast majority of hours, we see pricing very consistent with incremental costs, but when demand gets really high, we expect prices to rise, as appropriate, and as it tracks up that aggregate supply curve.

But to answer your question directly, no, we don't; we don't have any tariff-based method for addressing that.

COMMISSIONER KELLY: Joe, you do have a practice of issuing demand letters or the ability to issue demand letters to request that market participants discontinue actions that you believe violate PJM tariffs or procedures, correct?

MR. BOWRING: Yes.

COMMISSIONER KELLY: And have you -- how many times have you had to issue a demand letter?

MR. BOWRING: Exactly once.

COMMISSIONER KELLY: In what period of time?

MR. BOWRING: That was in --

COMMISSIONER KELLY: I mean, over what period of time?

MR. BOWRING: That was in six years, and part of the reason for that, is that people clearly don't want to receive demand letters, and what we typically do is -- I mean, participants have generally behaved very well and behaved consistent with the rules.

And, generally, if it is drawn to their attention that they are not being consistent with the rules, they behave consistently with the rules, and it's never really gotten to be -- it's interesting, because I have really gotten into the issue, and we haven't really had very many cases that come to the Commission, but if there's a disagreement, we all come to you.

COMMISSIONER KELLY: Thank you.

MR. BOWRING: So, another measure of market structure is the RSI, again, which indicates the extent to which one owner is required, in order to clear the market -- as you can see, these results are consistent with those that we saw for the HHI, that is, the RSI numbers below -- what we're concerned about is when it's below -- close to or below one.

In the ComEd area, it was below one for a very large number of the hours, and in PJM, overall, it was below one for only a very small number of hours, so it really confirms the results that we saw from the HHI.

CHAIRMAN WOOD: But with Phase III, though, which is the integration of AEP and ComEd, this orange line really is a thing of the past?

MR. BOWRING: Exactly. Both the HHI and the orange line go away, as of October 1st, yes.

Another measure, and one --

CHAIRMAN WOOD: I have another question. Before you had PJM, before the Phases II and III came in, did you dip into the yellow zone there, or the white zone, at all, at the very right end of that?

MR. BOWRING: For last year, the results were very similar; that is, for 2003, for the pre-integration PJM. There were only a relatively small number of hours, actually, in 2002 and 2003 where we dipped into the below-one, a very limited number of hours.

And in response to Commissioner Brownell, I was referring to Slide 14 before, which is the monthly load-weighted markup indices. And, really, this is a very direct measure of the extent to which the industrials and those who are concerned about whether prices, are or are not competitive.

Our average markup, that is, the difference between the market clearing price and cost, is about three percent, assuming that what we're comparing it to is the cost-based bids that participants submit. Those include a measure of marginal costs, plus ten percent.

These numbers are consistent with numbers we've seen historically, and while it certainly is the case that during some hours, the markups are well above this, the fact that the markups, on average, are about three percent, gives us comfort that the outcomes are reasonably competitive.

CHAIRMAN WOOD: Can that number be compared at all to the -- when we did the old historic form of regulation, the ROE that we would grant, or is that just the apple-and-orange comparison?

MR. BOWRING: Yeah, they're not really directly comparable. I mean, the market would leave after the dollars flowed through our financial structure to an ROE, but this is simply the -- the baseline is marginal cost, literally marginal cost. It's fuel costs times the heat rate, plus a small variable O&M adder.

Basically, whenever the price is more than that for the unit setting the price, you have a positive markup, so, you know, obviously the test that economists use for competitive price is marginal cost, to the extent we can measure it accurately.

And what this is telling us, is that the price is very close to the marginal cost of the marginal unit, on average. It's not -- it's certainly not happening in every hour, but, on average, it's very close.

COMMISSIONER KELLY: What's the upper limit that's acceptable, on average? You said that three percent, on average, was acceptable. What's the upper limit of acceptability?

MR. BOWRING: I mean, I don't think there is a bright line. I think I'd start to get concerned if it got significantly higher than that, for example, ten percent. One can calculate what the dollars are that are associated with that, and, again, there is some measurement error. It's important to remember that there is some measurement error in marginal costs.

At this point, we don't have a bright-line standard of what's too high.

COMMISSIONER KELLY: But three percent is acceptable?

MR. BOWRING: Yes.

Slide 15 presents statistics for a number of years on the extent to which we offer cap units. And, as you know all too well, PJM has a system of addressing local market power.

That system calls for offer-capping units which can exercise market power, when they are needed for transmission constraint.  What this indicates is the number of megawatts, average number of megawatts offer-capped, rose a little bit in 2004, but obviously the size of the market rose as well.

On a percentage basis, it rose, again, a very small amount, but basically it was consistent with prior years.  Typically, less than half a percent of megawatts are offer-capped.

The total number of units -- the total number of different units offer-capped in 2004, was, if I recall correctly, 187.  So, 187 out of some 900 or so units, were offer-capped at any point during 2004.

COMMISSIONER KELLY:  Do you have a sense of whether that is appropriate mitigation, or is it over-mitigation?

MR. BOWRING:  No, I think it clearly is appropriate.  There's a very well defined set of rules in PJM, which are really followed mechanically by the engineers.  Market monitoring has nothing to do with actually implementing it; they're simply applied according to a well defined set of rules, and, I think it has worked effectively.

COMMISSIONER KELLY:  And what do you think about the rules themselves?  Are the rules themselves appropriate?

MR. BOWRING: Yeah, absolutely, yes; I think the rules are appropriate. In fact, as you know, you have modified -- the Commission has modified the rules recently to address issues associated with frequently-mitigated units, those that are mitigated more than 80 percent of the time.

We're implementing that right now, and I think that was an appropriate modification for those units with basically small run hours and hours that -- and are primarily running only for transmission constraints and nothing else.

COMMISSIONER BROWNELL: Joe, transmission constraints are growing; is that a correct assessment?

MR. BOWRING: Certainly congestion is growing. I'm not sure that the number of constraints are growing.

In fact, we have numbers on constrained hours, and I believe the number of constrained hours is actually down. I mean, there are a lot of different ways to look at it, but I wouldn't say that, as a general matter, the number of constrained hours is increasing.

I mean, it's not trivial. There is a significant number of constrained hours; constraints happen a fair amount.

COMMISSIONER BROWNELL: And that is because of inadequate infrastructure?

MR. BOWRING: I think it results from the historical decisions about the most cost-effective way to address the need for power in areas. In some cases, if it's more cost-effective to build a CT, for example, on a peninsula or in a particular area, than it is to build transmission, the result will be congestion.

But congestion is not uniformly pejorative, at least in my view. And it reflects -- if the system has been built efficiently, it reflects an efficient outcome or can reflect an efficient outcome.

It may well be more efficient to burn gas or oil to meet load during certain times of the year, than it is to build a very expensive transmission line, which could basically bring in cheaper energy, year'round.

So, I don't think the answer is simple in every case.

COMMISSIONER BROWNELL: Nothing is simple when it involves money.

MR. BOWRING: Right

COMMISSIONER BROWNELL: But I guess the point of my question is whether or not the planning process is adequate to give that balanced look at what is the best solution, and as your territory has expanded, has that process expanded accordingly? Otherwise, you could see these numbers go up --

MR. BOWRING: Right.

COMMISSIONER BROWNELL: -- pretty significantly, and the reference to market power in certain kinds of markets, would also be expected to increase.

So, if you could -- because that has direct implications for market monitoring.

MR. BOWRING: Right, yes, it does. So, to answer your question, yes, I believe that the RTEB process and the economic planning process has continued to improve as PJM has improved.

I don't think it's perfect and I don't think the incentives for transmission construction and maintenance are perfect. I think work needs to be done there, but, nonetheless, in PJM, as you know, it's an economic plan-in-progress.

We identify un-hedgeable congestion and to the extent un-hedgeable congestion exceeds a certain threshold, we open a market window to see if there are any market participants to who want to try to solve the transmission, and if that fails or doesn't draw any interest, PJM then can order the transmission owner to solve the problem, and that's the process we're in.

That works. It's a fairly lengthy process, and I don't think it's perfect, and, right now, we certainly don't have a market mechanism to incent transmission construction or even to do maintenance as cost-effectively as it could be.

I think those are some areas where clearly there is a need for improvement.

COMMISSIONER BROWNELL: Thank you.

MR. BOWRING: Slide 16 shows what happened to the capacity market during the year, and, in fact, the most dramatic and interesting thing on this slide is that -- it's a somewhat complicated slide and I apologize -- the solid lines are to be read on the left axis and the dotted ones on the right, but really what it shows is that the difference between the obligation and the installed capability, adjusted for un-forced capacity, increased very significantly after the introduction of AEP. It was around 1,000 to 2,000 megawatts before AEP; it's about 10,000 megawatts afterwards.

And in an aggregate capacity market, that means that we're very long and there's very significant downward pressure on prices, so if you continue to have one big capacity market, I would expect, given these fundamentals, that the capacity market price would stay low for a number of years until load growth affects that.

CHAIRMAN WOOD: How -- go ahead, Sudeen.

COMMISSIONER KELLY: I was going to ask if this good news is tempered in any way by the transmission infrastructure?

MR. BOWRING: It is tempered, and it's tempered in the sense that it illustrates the fact that we don't have a locational capacity market and the problems that that shows. For example, again, as you know, we've had retirement issues in New Jersey, for example, and so what we have is a situation where the combination of capacity prices and energy prices in New Jersey, are not adequate to provide an incentive for existing units to stay in service, nonetheless, PJM requires them to stay in service, because we need them for reliability.

So, clearly, something doesn't compute, and what that suggests is, while we're long, overall, in the capacity market, we're clearly not long in certain areas, and that's really -- I mean, that's a significant part of the reason why we need a locational capacity market to have more targeted signals.

In some places, in some areas of PJM, we need a high-capacity market price, and in some areas, we don't.

CHAIRMAN WOOD: That sounds like two other markets to your north and northeast.

(Laughter.)

CHAIRMAN WOOD: That would actually reduce the seam to get that issue. Now, that's part of the discussions that are going on now with the stakeholders, correct, the locational component?

MR. BOWRING: Exactly.

CHAIRMAN WOOD: Among other changes?

MR. BOWRING: Exactly.

COMMISSIONER KELLY: Joe, can you -- this isn't -- you may not know this off the top of your head, but, what areas of PJM have been benefitted by the AEP capacity and which areas have not been able to benefit from it?

MR. BOWRING: I would say all of PJM benefitted. We have a more efficient dispatch; we have -- we're -- there's more base load; there are more base load units running around the clock, providing energy which is simply being redispatched, economically, instead of having to make a decision about whether to import or export and PJM had to be concerned about whether they're meeting a ramp limit or not.

So, overall, dispatch is more efficient, and I think the entire system has benefitted. Clearly, the farther east you go, there's a steady upward gradient in prices, as transmission constraints become more binding, and you certainly can't shift either ComEd nuclear power or AEP coal power, all the way to Newark in every hour.

COMMISSIONER KELLY: Thanks.

CHAIRMAN WOOD: Okay, I think that answered my question, too.

MR. BOWRING: Slide 17 shows really a result that's consistent with the overall capacity market measure I showed you a minute ago, and that is, overall, looking back all the way to 2000, capacity market prices have been showing a fairly steady downward trend.

Daily prices have averaged virtually zero over the last 18 months, and monthly and multi-monthly have trended steadily downward. The only exception to that was that we had a price spike in the Summer of 2004 in the daily capacity market. I got a lot of calls and I'm sure you got a lot of calls, and people were asking me to investigate whether it was market power.

We reached the very straightforward conclusion that it was not market power, that it resulted from fundamentals in that market. That market got very tight over the summer.

A number of participants decided that because they had been seeing that zero price for a long time, to shift their obligation into the daily market at the same time that there were less resources available there, and the price went up as a result. We know who set the price in every auction, and we're comfortable that those prices are actually consistent with the marginal cost of that capacity.

We actually spent a lot of time looking in great detail at those units and at the costs associated with those units.

But the overall point that this slide makes is that capacity prices have been trending downward steadily.

Slide 18 shows what's happened to forced outage rates over time, and, in fact, in 2004, forced outage rates ticked up a little bit again. They're now about eight percent.

There is a tiny orange square at the very last point, which shows that for the entire footprint, forced outage rates are also about eight percent. The blue line is where we have the most consistent historical data, and is for PJM Mid-Atlantic, including APS, but the orange shows the entire footprint.

CHAIRMAN WOOD: What do you think that is from?

MR. BOWRING: Increase in forced outage rates?

CHAIRMAN WOOD: Yes.

MR. BOWRING: We've looked at in great detail. I mean, we know that there's a relatively small number of units that account for it. There a lot of units with better forced outage rates, and there are some that didn't change.

CHAIRMAN WOOD: Are they necessarily older units?

MR. BOWRING: They are typically older units, and PJM certainly has a fleet that has a fairly significant number of quite old units in it, but we've done a fair amount of analysis, and there is no -- I don't have a clean answer that I can support with analysis.

CHAIRMAN WOOD: Okay.

MR. BOWRING: The next slide is sort of a measure of the way that all the markets work together, the net revenue. And what we've done here in the first column, is present the 20-year levelized fixed costs for three types of units, new units: A combustion turbine, a combined-cycle, and a new pulverized coal plant.

And then what we calculated was the revenues, the net revenues which would have resulted from what we regard as relatively realistic dispatch during the year 2004 and for every year from 1999 to 2004.

So, what this shows is the average net revenues over this six-year period. In every case, it's significantly below the cost of new entry, so in the case of the CT, it's about half the cost; in the case of a combined-cycle, it's about 55 percent of the cost; in the case of a pulverized coal unit, it's about two-thirds of the cost.

Actually, this is the first year we did the pulverized coal unit, and it surprised me slightly. I thought that net revenues would be a larger proportion of fixed costs for the pulverized coal unit, but in every case, what this shows is that for new units, the incentive right now, based on historical net revenues -- and they were actually down in 2004 -- has not been adequate to cover all of the costs, that is, a return on and of capital, for a new entry.

CHAIRMAN WOOD: So would you expect anybody to build in PJM, based on this?

MR. BOWRING: It certainly isn't a positive incentive signal, I think it's fair to say. I mean, if I was a potential investor and thought these conditions would continue, I probably would not invest.

Clearly, investors, rational investors, require a reasonable expectation that they are going to cover 100 percent of the costs, absolutely. And that is, again, a significant part of the reason we're looking at a modification to the capacity market, because if we're seeing areas where we're literally short of capacity, then something is not working and these net revenue numbers are a pretty dramatic illustration of that.

CHAIRMAN WOOD: But that's just the snapshot of the last year. It's really the projection of what's going to be, that really drives the investment.

MR. BOWRING: That's correct.

CHAIRMAN WOOD: And it's because there's not really a very good number to hang your hat on for forward projections, because there's not a forward -- really strong forward curves; is that what's the problem?

MR. BOWRING: Yes, that's correct. One of the features, as you know, of at least the capacity market construct that's been talked about so far with the stakeholders and PJM, is one that looks forward four years, that gives a price signal far enough out so that people can plan to build, but right now, based on the energy market forward curves and the capacity market forward curves, they really don't go out, the bilateral market doesn't go out very far and certainly doesn't give a signal which is very different than what the historical data show.

COMMISSIONER KELLY: Is it your sense that if we established a forward capacity market, that we would see an incentive for investment, and, if so, would it be -- in which locations do you think it's likely to be?

MR. BOWRING: I think the incentives would be significantly improved. I think the areas we would expect to see higher prices right at the beginning would be in eastern PJM and basically east of the interface. And PJM has done some simulations using the model and that's precisely what they show is that we would expect to see higher prices where the capacity is needed in the East and not in the rest of PJM for at least the next three or four years. But, as the market tightens, the prices grows, we would expect.

COMMISSIONER BROWNELL: Have you had any retirements, the kind of activity we show in Texas when the markets got competitive or do you anticipate any?

MR. BOWRING: If you're referring to brand new combined cycles retiring or mothballing, we have not seen that behavior. We have seen generation owners sitting down and looking in very cold light whether the units they are continuing to operate are making money and whether it makes sense to continue to operate them.

When we've looked at the proposed retirements, it's been our conclusion that the decisions to retire were rational in a business sense or an economic sense, that is, those units were not covering their annual out-of-pocket expenses and they hadn't been doing so for a number of years. So, while we certainly haven't seen a rash of retirements, we have seen retirements in some critical areas, particularly, the East where we can't afford to lose the capacity.

Does that answer it?

COMMISSIONER BROWNELL: Yes.

COMMISSIONER KELLIHER: Joe, I just want to ask about generation additions. Have there been much additions in the past two years. And, if so, where in PJM have there been additions and are there licensed units where construction activity is halted? Is there much under construction right now?

MR. BOWRING: I don't have an exhaustive answer to that, but we have -- and their number is in the report -- we have added significant capacity over summer-to-summer 2002 to 2003, 2003 to 2004. We certainly have added capacity. The near-terms Qs are declining somewhat, although there still is significant capacities in the Qs. I don't have any indication that there are existing projects which have stopped or slowed because they're concerned about the price signals, but I don't claim to have exhaustive knowledge right here.

It is the case also that the farther out you go the less effect on the Qs, but I think that reflects the fact that those in those Qs have to make a smaller financial commitment to remain there. And, as you get closer, we'll begin to see the incentive effects.

COMMISSIONER KELLIHER: Do you track percentage completion of license plans to see whether it's progressing?

MR. BOWRING: Yes, we do, although I don't know the answer off the top of my head.

COMMISSIONER KELLIHER: Thank you.

(Slide.)

MR. BOWRING: Slide 20 simply illustrates that PJM, for the first time, changed from being a net importer to being a net exporter really reflected the addition of ComEd. ComEd was a net exporter prior to integration, continue to be and those net exporters were enough to offset the net imports from the earlier configuration of PJM.

(Slide.)

MR. BOWRING: The next set of slides are really about the ancillary service markets. Slide 21 shows HHI's for the regulation market. And, again, reflects what I indicated at the beginning, which is the only regulation market which we believe is structurally competitive is the Mid-Atlantic one. That is not true for either ComEd in Phase II or the PJM Western region Phase III market.

CHAIRMAN WOOD: And so those, in fact, are not now -- they're cost-based?

MR. BOWRING: They are cost-based.

CHAIRMAN WOOD: All three? Or is PJM marginal?

MR. BOWRING: PJM Mid-Atlantic is price-based, market-based. There is only one other regulation market in PJM now. The fact that there are three reflects the fact there was one for ComEd prior to integration of AP. Now there's one, PJM West South regulation market and that continues to be cost-based.

And just to be clear about what that means, we have not only cost but there's a margin added to that. And, finally, that price there when it was paid it was a market clearing price, so everyone receives the price of the highest cost unit, including the opportunity cost of the highest cost unit. And opportunity costs are a very significant proportion of the compensation. That's actually illustrated on the next slide, 22, which shows the opportunity costs and the non-opportunity cost piece of those regulation clearing prices.

(Slide.)

MR. BOWRING: Slide 23 shows really the same thing for the spinning markets, that is, that concentration is really --

COMMISSIONER KELLY: Joe, is the opportunity costs market-based or cost-based?

MR. BOWRING: It's absolutely market-based. And the opportunity costs reflects the fact that, if your regulating unit -- PJM wants to make sure you're indifferent between generating electricity or of standing ready to provide regulation. So you are paid a price based on the difference between whatever the market clearing price is in LMP and your offer. The same thing is true in the spinning market. That in all of our spinning markets we see relatively high levels of concentration and those markets remain cost-based. And, not surprising, as a result, the results continue to be competitive.

(Slide.)

MR. BOWRING: Let me just go to the last slide, which is Slide 25 and that's an aggregate measure of congestion and there are lots more details in the report about how the Event Hours break down and how they break down across here. But I wanted to make sure to present the overall level of congestion.

Again, the overall level of congestion was up, one might say, dramatically. It was up 62 percent. But, of course, PJM also grew. And, if you normalize it by dividing it by the total billing, which we do here, congestion rose as a percent of total PJM billing from 7 percent to 9 percent. But, again, congestion, particularly, when you're integrating new areas, is not necessarily a pejorative. But, in fact, it reflects the fact that we're now dispatching a very large footprint and it's not physically possible, given the current transmission system, to get the cheapest power all the way from the West to the East.

That concludes my slides.

CHAIRMAN WOOD: Joe, I'm looking back to the ancillary services. Our cutoff filing, though, that PJM made was it just to do the PJM Mid-Atlantic and market-based rates?

MR. BOWRING: Way back in 2000, I filed an affidavit on the Mid-Atlantic.

CHAIRMAN WOOD: I think it was last year.

MR. BOWRING: Yes. We did make a filing and market monitoring filed their report. And what we said was that at that point it looked as if there would not be structural conditions to support competition. Actually, we're going to send you a report later this week on the balance of the West market and it continues to be our view that for AEP along, and you can see that in the state of the market, where we concluded it's clearly not competitive.

Looking forward to the inclusion of Dominion, we cannot conclude that it will be competitive. What we'll suggest in our report is that we remain cost-base for a while until we see some actual data. Again, that's an issue that you all have seen and that we've filed that report, but it's based on analysis very much like this.

CHAIRMAN WOOD: But the filing that PJM did make to move market-based rates was for this one on page 21 on the left?

MR. BOWRING: No. PJM actually in -- I think their filing was October 1st of last year -- actually filed for market-based rates, including the West regulation market. That is the regulation market for which I recommended that we not go to market-based rates until such time as we had more data.

CHAIRMAN WOOD: That's gone into effect?

MR. BOWRING: No. It remains cost-based. The recommendation of PJM was effective with the integration of Dominion, so nothing would happen until May 1st.

CHAIRMAN WOOD: Okay.

COMMISSIONER BROWNELL: Joe, just a quick question.

I'm sorry. Did you have more?

CHAIRMAN WOOD: No. That's good. Thank you.

COMMISSIONER BROWNELL: Okay.

Just a quick question that you didn't cover, but is referenced on page 94 of your report, and that's demand response. And your conclusion, if I am reading correctly, based on a survey is that the effect of retail markets has increased demand response, has given more opportunities to participate. I didn't quite understand what you were saying there.

MR. BOWRING: We weren't totally clear? I'm sorry.

COMMISSIONER BROWNELL: No. You were probably very clear. It's probably me.

MR. BOWRING: Yes. What we tried to measure was both the impact of PJM's programs directly as well as the programs run by those participating in the retail markets. Clearly, they both contributed. The overall level is significant, but it's not dramatic and there's still, obviously, room for improvement. PJM is actively engaged in trying to redesign the DSR program so that it's better integrated into the market and give better signals going forward.

But again, in part, it's not surprising we didn't see a lot of this type of load response in 2004 because prices never exceeded on an average -- on an overall basis of $180.

COMMISSIONER BROWNELL: We're seeing some innovative demand response -- internet-based demand response used in New England in a different way, but the same internet-based in New York, California -- one of their programs. Is that something -- because we've been talking about demand response in PJM since I was a state commissioner and we're just always on the edge of redesigning. Are you looking at that? How close are we to the redesign? Is there a process by which people can come in and look at kind of the next phase? I think this is pretty traditional kind of stuff.

MR. BOWRING: It is pretty traditional, but I think the object of PJM is not to be actively involved in DSR programs themselves, obviously, but to try to provide the institutional and incentive structure so that creative middlemen of the type you described can come in and do internet-based applications or whatever type of applications make sense to aggregate load and we are seeing some very creative approaches to DSM.

I've talked to folks in Chicago and their doing very interesting things with commercial buildings. There are other DSR providers elsewhere in PJM. So, in part, it's trying to find the right balance between creating a set of rules that provide the incentives and then letting market participants react to those.

COMMISSIONER BROWNELL: Does that survey reference those specific programs -- the innovative programs you're seeing in different --

MR. BOWRING: No. That's not so much a program as a particular vendor who has a creative approach to managing energy in large commercial buildings.

COMMISSIONER BROWNELL: This is a topic about which we have lots of conversations in all of our regional meetings. Could you share that survey with us so that we could see.

MR. BOWRING: Yes. Absolutely.

COMMISSIONER BROWNELL: Thank you very much.

COMMISSIONER KELLY: Joe, I'd like to go back to the PJM Western and South region regulation market and the market-based rates that will go into effect in May. Obviously, you're concerned about whether or not it will be concentrated.

Do you have the ability to mitigate? Is your current ability to mitigate sufficient to take care of any problems that you might expect to see?

MR. BOWRING: We have no ability to mitigate in the regulation market.

COMMISSIONER KELLY: Would you suggest to us that you should?

MR. BOWRING: To me, the most sensible and prudent thing to do is to leave it cost-based until we have some data, until we have three months or maybe until we get to the summer -- five months, perhaps. Then we'd be able to make a better evaluation and then we could share that information, obviously, with PJM and with you and we could all sit down and make a rational decision. It might make sense to let it go forward on a price base after that with some fairly careful scrutiny and with some ability to effect the market if results aren't competitive. I think it's right on the cusp. It's a very difficult call.

COMMISSIONER KELLY: If you see that results are not competitive, what action would you expect to take, vis-a-vis, FERC?

MR. BOWRING: Right now, what my action would be -- I would let you all know it's occurring. I would talk to the market participants and I would file something with the Commission.

COMMISSIONER KELLY: Under our new expedited process?

MR. BOWRING: Yes, exactly.

COMMISSIONER KELLY: Thanks.

CHAIRMAN WOOD: Any questions for Joe?

Bill?

MR. HEDERMAN: I have one quick question.

Joe, on slide 25, what was the significance of the total column on congestion costs?

MR. BOWRING: It is simply -- I mean, we've reported a total. It's the total amount of congestion paid by participants and it's one way we track congestion. For example, when we compare total FTR payments to congestion, it's one measure of the sufficiency of FTRs as a hedge, for example.

MR. HEDERMAN: Thanks.

COMMISSIONER KELLY: Joe, the differences in price between the real time and the day ahead markets in PJM, real time prices are typically higher. Why is that, do you think?

MR. BOWRING: Well, actually, for the first time in 2004 real time was higher. Prior to that, day ahead had been higher from any from to 30 to 60 cents or so. We've puzzled a little bit over why that flipped. I'm not entirely sure why it flipped. They're still quite close, but it did reverse this year and it was, in part, associated with the integrations but I don't have a great answer as to why it did.

COMMISSIONER KELLY: Are you still looking for an answer?

MR. BOWRING: Yes. We're still looking.

COMMISSIONER KELLY: Okay.

CHAIRMAN WOOD: Did you use virtual bidding in PJM?

MR. BOWRING: Yes. Virtual bidding is used extensively. Virtual bids actual set the price in the day ahead market a majority of the time.

CHAIRMAN WOOD: I saw that coming up in David's report on rates as well.

On the last slide that Bill just asked you about -- the congestion chart -- I'm looking at the number there in 2004, 808 million. How did the FTRs that customers have to hedge congestion how does that play against that number?

MR. BOWRING: The numbers in the report I believe it was -- I don't want to give you the wrong number -- but it was in the high 90 percent. I think it was, I believe, 98 percent for the planning year ended May 31, 2004. We're now in a planning year basis for FDR, so it goes June 1st to May 31st. And right now, going forward, we're at about 100 percent, taking account of the fact we've been more FTR revenues than costs in some of the months so far. So it's very close.

CHAIRMAN WOOD: Just stepping back, who pays and who gets money? That $800 million for 2004 -- walk me through. Just kind of dumb it down a little bit. Who paid the 800 and who does it go to?

MR. BOWRING: Sure. Congestion costs are paid whenever -- obviously, you have to turn on a unit out of merit and prices are higher in an area. The way it works is that if you're shipping power into that area you get the LMP where you sit. You don't get the higher LMP in the area. So the result is that load is paying more than generation is receiving and then FTRs provide a mechanism for taking the excess collections and reimbursing those who hold FTRs as a hedge.

CHAIRMAN WOOD: If you were a customer in that load pocket and had the FTRS, you'd pay it but you'd get it right back?

MR. BOWRING: Exactly. If you were fully hedged with an FTR, you'd be indifferent to the congestion and that's part of the reason we look at unhedgeable congestion as one measure of whether we need transmission upgrades because that's congestion that's hedgeable either by an FTR or by inexpensive generation in the load pocket.

CHAIRMAN WOOD: So that's, in effect, how a customer then makes the choice as between whether they ought to put some generation in that load pocket, build some more transmission in that load pocket or not would be if they don't have a hedge. So they're paying the raw price. But the ones who are in there and are hedges they don't get any price signal.

MR. BOWRING: If you're fully hedged, you don't get a price signal. That's right.

CHAIRMAN WOOD: So that really is sending a signal that, well, we did dispatch out a merit, but it was probably more economic to do so in the aggregate for a time?

MR. BOWRING: Yes. The theory is that the FTRs are assigned consistent with the capability of the transmission system to deliver energy.

CHAIRMAN WOOD: Right.

MR. BOWRING: So the theory again is that those on the margin who caused load in that load pocket to be above the transmission capability appropriately paid the congested price.

CHAIRMAN WOOD: Because they wouldn't have a FTR.

MR. BOWRING: Exactly.

CHAIRMAN WOOD: Okay. That' makes sense. Good. That helps me a lot.

So these numbers then would not be the congestion charges slide 25. The congestion charges on slide 25 are total congestion, not hedged and unhedged. It's hedged plus unhedged?

MR. BOWRING: That's correct.

CHAIRMAN WOOD: Is the unhedged broken out in the report somewhere?

MR. BOWRING: Yes. We have the FTRs in there.

CHAIRMAN WOOD: That's where you get the 98 percent. The 2 percent would be the unhedged.

MR. BOWRING: Yes.

CHAIRMAN WOOD: Okay.

COMMISSIONER KELLY: And does it show where it exists -- the unhedged congestion?

MR. BOWRING: Yes. It does. It actually lists the constraints for which we actually went out to market during 2004.

COMMISSIONER KELLY: Now are they primarily in the eastern part?

MR. BOWRING: They are primarily in the eastern part. Yes.

COMMISSIONER KELLY: Did any place surprise you?

MR. BOWRING: No. One of the big ones is Beddington, Black Oak. It's a big interface between the old APS and PJM and that actually has gone through its market period. It is now at a point where PJM is working with the transmission owner to get fixes put in place.

COMMISSIONER KELLY: Thank you.

CHAIRMAN WOOD: Any more questions for Joe.

(No response.)

CHAIRMAN WOOD: Joe, I just want to say I appreciate your long advocacy for good markets and markets that take care of customers, so don't ever change.

MR. BOWRING: Thank you, sir.

(Laughter.)

CHAIRMAN WOOD: Mr. Patton, welcome back.

MR. PATTON: Thank you. I appreciate the opportunity to come talk to you. It's an exciting time in the Midwest. In fact, I have very positive conclusions, in general, about what's happening out there. But, if you hear my beeper go off, my conclusions might change in real time.

(Laughter.)

COMMISSIONER BROWNELL: If your beeper goes off, we're closing down the meeting.

MR. PATTON: Typically, I come and talk about the state of the market and our analysis of what happened in the previous calendar year. What I'm going to do today is talk about 2004 and the markets that have been facilitated by the MISO in 2004 for about half time. And, actually, devote a little more than half of the attention to what's been happening in the first week or so of the new market.

It's an interesting transition and it goes exactly to your question to bilateral transactions because the Midwest has gone from an exclusively bilateral market to a nodal market. And I think there's a couple of things to recognize in response to your question about how do bilaterals work in the context of nodal? Does it help? Does it hurt?

It certainly helps from the perspective of the price transparency that Joe was talking about. You really can't see a good spot price that is a real time price without the nodal markets. But, even more than that, I think it's a facilitator of bilateral transactions in that before you have a nodal market I may have a $30 generator and signed a $40 contract for difference with you. So I've locked in a $10 profit. Right.

In real time, though, with the nodal market -- and I'll run my generator and I'll supply you and that's the way the old world worked. In the nodal market, though, those bilateral contracts largely become financial. So I don't have to run my generator any more to supply you at $40. And, if you have a spot market that's pricing at $20, I'll buy in the spot market at $20 and ramp my unit down. Now I've doubled my profit, right, buying at $20 and selling at $40.

So, as a bilateral transactor, it actually lowers my cost and increases my profit. And the societal benefit is you get better dispatch because I don't walk myself into running a generator when there are cheaper alternatives out there.

COMMISSIONER KELLY: And how is the buyer going to respond to that situation over time? Is the buyer going to negotiate a different contract or a better contract? Or is the buyer going to move out of the bilateral market?

MR. PATTON: Well, in that context, the buyer is -- the decision to contract bilaterally is largely a risk management. Buyers can buy anywhere from long-term forward to spot. And, when they sign forward contracts, they're essentially hedging themselves against the volatility. The volatility increases as you get closer and closer to the spot market, which is why the day ahead usually prices a little bit above real time because you're buying a safer product. Real time markets, generally, are about four times more volatile than day ahead.

COMMISSIONER KELLY: So you wouldn't expect to see the buyer change his strategy, but you might expect to see more sellers get involved.

MR. PATTON: They have increased options, clearly. If we get to a world where people can respond in very short order, in terms of their consumption decisions, they're finally going to see the true value on a real time basis of power in the spot market and can choose, for the first time, not to consume. In the old Midwest market, you really didn't see that. You didn't see either the very short term signal -- you know, the hour-to-hour. You also didn't see the congestion. For a couple of years, we've been showing the results saying that the bilateral prices really don't reveal the transmission congestion in the Midwest, which is one of the real advantages of going to nodal markets as well.

COMMISSIONER KELLY: At the risk of prolonging this too long, there's been a debate that I've observed about the number of nodes and that at some point you reach the magic number and too many nodes can actually decrease the competitiveness of the market. Can you give me your opinion on that?

MR. PATTON: Yes. That's not correct, not to sugar-coat it. The reality is that power really does have value that is dependent on location and on what voltage transmission system you have. So you might be sitting across the street from me on a low voltage piece of the transmission system. I'm sitting on a high voltage piece and power is worth twice as much where you are because the constraints on the low voltage system makes it difficult to deliver there.

It's always better to show that because it gives people the right incentives to produce and to consume. Now, for purposes of ease of transactions, it is relatively straightforward to develop trading hubs and zonal prices for people that are simply a weighted average of prices in an area. So you take all the prices and you develop a hub price and people then can contract on a forward basis at that hub and it can be fairly liquid. But the problem comes when you eliminate those locational prices because then you go from having a system where all the congestion is priced to a system where a big portion of it is not priced and it then becomes difficult to hedge it and to get generators to respond effectively.

If you read some of the recent reports in Texas, you'll see that sort of issue where they have a zonal crisis, but they have a lot of congestion that's not priced. So that's probably a pretty good case study for the kind of difficulties you have by not just pricing all the points.

COMMISSIONER KELLY: Should FERC be doing anything about that?

MR. PATTON: About what? About Texas?

(Laughter.)

COMMISSIONER KELLY: About the hub prices.

MR. PATTON: I think it's good to encourage RTOs to publish hub prices and I think most of them are. The Midwest has four hubs. PMJ has hubs. New York has zonal prices that they settle with load at and they essentially serve the same purpose as hubs, so I'm not sure there would be much gain there because they price, for example, the New York City zone on a very similar basis that you'd calculate a hub price. And New England, as one hub, so I think all the RTOs are publishing hub prices because they understand the value it has to the forward contracting market.

COMMISSIONER KELLY: Thanks, Jim.

MR. PATTON: I just wanted to throw that out. And, at the end of this section on the Midwest 2004 markets, I'll give sort of a summary of my conclusions on the Day One markets, which is 2004 and the Day Two markets, which is what we're in now.

The 2004 state of the market report addresses the areas where the Midwest ISO had primary responsibility. Essentially, the two most important things they did, historically, is sell transmission services under Order 888 process and they are the reliability coordinator for actually a footprint that's larger than the market footprint. And, by reliability coordinator, what I mean is they're responsible for monitoring the flows and calling TLRs, which is the primary means to relieve congestion in the sort of bilateral market.

So the 2004 report covers transmission service. It covers the transmission operations and reliability coordination process. It also looks at various aspects of the supply and demand in the Midwest, bilateral prices and network designation by basically the integrated utilities in the Midwest and what that did to transmission capability.

(Slide.)

MR. PATTON: So, if we go to the first figure, I'm going to be showing you monthly average peak and off-peak bilateral prices in the Midwest and I plot against those prices the fuel prices for natural gas and coal. And what you'll see from that figure is that the peak prices are significantly higher than the off-peak, which reflects the fact that natural gas is on the margin a much larger share of the time in the peak hours versus coal, generally, on the margin in off-peak hours.

The other thing is you can see from the trend in natural gas prices is that the peak prices are driven by the natural gas prices. The coal prices did increase significantly over the year, but there's not much of a relationship between the peak prices and coal because those are on the margin relatively infrequently.

Off-peak prices are actually the lowest in the summer. The trend that you see in the off-peak prices is driven by the fact that generation -- you have the most generation available in the summertime because nobody's scheduling plant outages then. And in 2004 we had an extraordinarily mild summer from a weather perspective, so we basically had no shortages anywhere, either Northeast or in the Midwest.

(Slide.)

MR. PATTON: The next figure in my presentation essentially focuses on the integration of ComEd and AEP into PJM. And the reason that it's an issue in the Midwest is because the systems are sort of intermingled with one another and the transmission facilities in the Midwest are affected by the integration of ComEd and AEP. So it's something that Joe and I were jointly monitoring.

When ComEd was integrated in May, they operated over a 500-megawatt firm path and that limited the West the East transfers that resulted from the PJM dispatch. When AEP was integrated, PJM then could fully dispatch the system all the way across from ComEd to the traditional PJM area and it resulted in larger flows in general.

Initially, there were -- when I say "initially," I mean the first few days. There were some serious overloads on the NIPSCO system, a lower voltage system largely due to the fact that some of the NIPSCO flowgates were not designated as coordinated flowgates. You may remember that there's a market to non-market interface that allowed PJM and MISO to coordinate the flows and now there's a market-to-market interface. The mechanism by which that interface works is that you designate those flowgates where both RTOs affect the flowgate.

The overload problems in the NIPSCO area were largely resolved by designating the NIPSCO flowgates as coordinated flowgates, which allowed MISO to then use the TLR process to cause AEP to redispatch when those transmission interfaces were getting to their limit.

And where you can see from the figure, which should be figure 6 in what you're holding, is that the TLRs on the NIPSCO flowgates increased dramatically in the fall, particularly, after the integration of AEP, which is just evidence of really the market to non-market interface operating.

The result of that, though, is the difference between the ComEd prices bilaterally and the PJM West prices converged to a greater degree than they had before the integration. So that's evidence that the economic dispatch by PJM over that area caused prices to converge better than relying exclusively on bilateral transactions going from West to East.

CHAIRMAN WOOD: How would that look today -- that figure?

MR. PATTON: How would it look today?

CHAIRMAN WOOD: After the April 1 beginning -- would that change things -- the fact that they're all being dispatched on LPM-type market across the whole footprint as oppose to having the market to non-market?

MR. PATTON: Yes. It should look different. What should happen is that the transactions all along the path where AEP and MISO are both operating that transactions are responsive to prices so that it should not be the case that PMJ's dispatch is governed exclusively by what the price is in ComEd and what the price in PJM West is in their software. It should be the case that the price in Michigan matters, the price in southern Ohio matters, the price in Wisconsin matters from the perspective of what's been importing and exported between those areas.

So, for example, maybe Wisconsin bids power away from PJM West so that ComEd power flows into Wisconsin because the value of energy there is higher. That's what you would want to happen. And I have some figures to show that's essentially what is happening. There are some improvements that I think could be made, but I think that we do see that the interchange between the PJM areas and the MISO areas are responsive to real time prices. In fact, they may be more responsive than some of the transactions that we've shown you in years past between New York and PJM. So that's very encouraging, given that we're just coming out of the gate. But we'll get to those figures and I'll remind you what you're looking at when we get there.

(Slide.)

MR. PATTON: The next figure shows the TLRs that were called by the Midwest ISO as well as the gigawatt hours that were curtailed because of the TLRs. You can see that there's a spike in curtailments in 2004 -- in the fall of 2004. Largely, that's attributable to the curtailments associated with TRLs on the northern e-car path that was the result of the comment integration. That's not necessarily a bad thing. What that means is that some bilateral transactions are being squeezed out by PJM dispatch, but as long as the prices are converging, that's really from a -- when you're trying to diagnose whether the world is better or not, when you want to look at the convergence of prices geographically when constraints aren't binding, too. And, if you see the convergence proving, then you're seeing benefits. So that's what you're seeing with the curtailments there.

You'll see that the TLR 5 events go down significantly in 2004. TLR 5s are of particular concern because you're cutting firm load and firm transaction when you're in TLR 5. The reason that they went down significantly in 2004 is because the North One's area had an outage in 2003 that resulted in TLR 5s on almost a daily basis for a period of time. Once those units came back into service in 2004, we didn't have those same problems.

The other source of the TLR 5 is associated with the non-MISO participants in the MAPP area -- the public power entities that transact and have no obligation to curtail. So we sometimes get into situations where flowgates in the Iowa area are overloaded because of those transactions and it can cause the TLRs to rise to a level 5.

(Slide.)

MR. PATTON: I think the last figure I'm going to show you for 2004 is the transmission reservations from 2002 to 2004. These are the number of requests. We do a similar chart showing the volume of requests in gigawatt hours.

You can see that the number of requests have risen substantially. The volume has risen less substantially, but I think what I would say, just in general about this, is that this, in part, I think is attributable to the benefits even without a nodal market of having a large RTO coordinating transmission service. Because transmission inherently is something that needs to be well coordinated because everyone's generation and load affects everyone else's transmission. So, even if you're in an Order 888 world, having a central coordinator of service allows you to sell more service.

Our conclusion, in general, was that the Midwest ISO did a pretty good job of selling transmission service as well as operating the system under its TLR structure. However, we identify in our report a number of problems with Order 888 type service. Problems that prevent the full utilization of the system and they're problems that are difficult to resolve without modifying requirements under Order 888 or moving away from this sort of service in the first place.

And the three areas that we identify that have been problems in the Midwest are participants failing to confirm requests for service that are approved. They can essentially request service. It gets taken out of the market. Nobody else can have it. It's approved. And, until they confirm it, they have no obligation to pay for it. It cost them nothing. so they can sit and hold it. And, if they decide that they don't want to use it, then they can let it lapse at the very end. In fact, in a timeframe where nobody else could pick it up and use it.

COMMISSIONER KELLY: Have you seen much of that occurring?

MR. PATTON: Yes.

COMMISSIONER KELLY: Is there a way to know?

MR. PATTON: Yes. Quite a bit. And we do screens to identify the portion of this that we would call "hoarding" where we look for paths where people had approved requests that caused the available capability to go to zero, caused some people to have requests denied. And then, when it was unconfirmed, ultimately, the transmission went unused. I think we have a set of like four criteria. It generally is the case that a fairly small share of this falls in the hoarding category, but it still is inefficient and does tie up transmission. What it does is it gives people a free call on transmission. And, if you give people a free option, they're going to take it. It would be irrational for them not to, right.

COMMISSIONER KELLY: Do they accrue any other gain than a free option?

MR. PATTON: No. There's an economic gain to acquiring that option and then exercising it when there's an economic benefit. The purpose of our hoarding analysis was are they using this as a mechanism to block other people from using transmission paths. So it could be that somebody who has load in a certain area may want to prevent other people from being able to use transmission to come into the area and could do it by this means and that's where we haven't seen a big problem. So it doesn't look like they're gaming with it.

COMMISSIONER KELLY: And so what is their incentive to do it? Is it less risk?

MR. PATTON: Purely economic. So, for example, we see a lot of this between Synergy and TVA. There's not always a positive price differential between Synergy and TVA, but if I can reserve transmission. And. when I do see a price difference, then I will confirm the request and ship power to TVA.

COMMISSIONER KELLY: Without paying for it.

MR. PATTON: Yes. You'll pay for it only when you confirm it and you don't have to pay to just sit and hold it.

COMMISSIONER KELLY: And that's what you meant when you said it's a free option?

MR. PATTON: Yes.

The second issue is over-designating network resources. People call tie up a large share of the transmission capability by designating far more network resources than the load that they're serving. We've seen that this an issue in the Midwest, but only with a limited number of participants. So you'll see those results in the report. And this is another area where there isn't explicit guidelines on what a transmission provider should do or what the Midwest ISO should do if it sees that someone taking network services and designating far more resources than they're load. One thing just to remind you of is when you designate a network resource it's essentially firm, so it eats up firm capability on the system.

And lastly, and this relates to the queing of long-term transmission service, the queing mechanism is really pretty dysfunctional when it comes to procuring long-term transmission service. If I have long-term transmission service, there's a renewal process whereby other people who want the service can put in a bid. There's no economic option that says the one who's willing to pay the most gets it. That's generally not allowed. You can only charge up to the embedded cost. So what it is, is it's a queing process and the person with the service gets the right of first refusal and gets to refuse transactions on a transaction-by-transaction basis or a request-by-request basis and there's nothing that stops you from putting in request against your own service.

So, if I have the service and I want to renew and I don't want to have to pay more or extend longer, I can put in 30 requests and I have 15 days to respond to my own request. So I can basically prevent anyone else from getting that transmission.

COMMISSIONER KELLY: Do you see that happening?

MR. PATTON: Yes. We see a lot of self-competing requests. We have some criteria that we use to identify people who are putting in requests to compete with themselves. But it's a very -- I think you saw some dockets on the IMO Michigan interface. These are valuable interfaces where price can't clear it, so people are going to use whatever mechanism they can to jostle with each other to try get the transmission capability because it's valuable.

CHAIRMAN WOOD: And price can't clear because it's got that embedded cost. Right?

MR. PATTON: Yes. Midwest ISO is already charging -- they had been discounting some of their export paths, but they're not discounting that one anymore because it's fully subscribed.

CHAIRMAN WOOD: I think that's in here, too. Just for the benefit of everybody -- I know a number of pending dockets are coming up in this discussion and rather than stifle the discussion, we'll file your two reports and the transcript in the relevant docket. So Cindy has given me that note already. So, please, go ahead.

MR. PATTON: That's a load off my mind. I've never been great about censoring myself when it comes to trying to figure out what's pending.

(Slide.)

Okay. So the final slide in this section is a text slide where I just --

CHAIRMAN WOOD: Excuse me. But none of those problems have been remedied by anything in the TMT or Day Two or anything. Correct?

MR. PATTON: That's a good question. No, I don't think so.

CHAIRMAN WOOD: To get transmission service --

MR. PATTON: Certainly, most of the transmission service internal now is really governed through the FTR allocation process because of the value of transmission internal to the Midwest ISO is now being captured through FTRs, but the external transactions --

CHAIRMAN WOOD: -- will still be handled through this mechanism?

MR. PATTON: Yes. You're still going to have to reserve the long-term service.

CHAIRMAN WOOD: There was some customer complaints earlier about the length of time it takes to get -- once the file for reservation requests -- to actually get an answer. Is that something that's captured in your report as far as the timetable?

MR. PATTON: Yes. We had looked at that last year and we haven't finished that analysis this year. We think the issue there largely was with the longer term service and the longer term services is more difficult and you get a lot of long-term requests and you have to put them in study. The shorter term service was more predictable in terms of how quickly it gets processed, but we're going to have that in our report.

CHAIRMAN WOOD: While we've got that, Joe, what does PJM do to prevent that kind of squatting on your rights type approach?

MR. BOWRING: We've had complaints from time to time about people -- it's a related matter, not exactly the same, but attempting to really hoard ramp because ramp, as with David's case, is free. But, nonetheless, it's valuable and one way to do that is to have a request and let it -- PJM has a set of rules, as MISO does, to basically take it back with a certain number of minutes remaining before the transaction becomes final. We had seen an increase in the number of such transactions. So I got up in front of the MC and said several times that we'd seen this. It's actually interesting. I was getting complaints from people who were themselves doing it at different times. So, once I pointed it out to them, everybody sort of settled down.

I don't think it was people intentionally trying to behavior anti-competitively. They were, as David was saying, behaving rationally. But, when it was pointed out to them that the effect was anti-competitive, they stopped doing it. So we do watch it. We don't have any direct authority to do anything about it, but I think that participants have generally been intending to do the right thing.

COMMISSIONER KELLY: David, and Joe also, if it's relevant to you -- do you have a process within the RTO that allows you to bring your observations in a formal way to the members of the board so that they could potentially take action. For example, filing a Section 205 change to their tariff to respond to these?

MR. PATTON: Sure. We basically have the ability at any point that we think there's a problem to alert the board. And, in fact, we would be alerting you simultaneously.

COMMISSIONER KELLY: Is there a regular process? Do you report every quarter or do you report as necessary?

MR. PATTON: Yes. The board has a markets committee that meets regularly. I don't know how regularly they're going to meet now that the market is operating -- less frequently than before. But, generally -- most of the boards that committee will meet monthly or they may skip a few months, but in every one of those meetings I'll give a report on what's happening and any issues that are coming up. But, even outside of that process, immediate problems that should be dealt with through a FERC filing would be transmitted to them outside of the normal meeting process and OLMI would be aware of it at the same time that we were alerting the board of it. So you'd have some heads up before you were seeing a FERC filing and all communication stops.

COMMISSIONER KELLY: Well, some of the observations that you just made about some of the drawbacks to the current Order 888, do you anticipate bringing those to the attention of the board?

MR. PATTON: Yes. And some of these were in last year's report and the problem is that a lot of them are difficult to solve under the current constraints of Order 888. For example, we had the idea that one thing that might make a lot of sense is to not remove the capability from the transmission system until a participant confirms the request and to allow participants to put in pre-confirmed requests so that they request service and they tell MISO if it's available and you're going to approve it confirm it immediately. And what Order 888 requires is that once a request for service is made that you dock the capability of the transmission system.

In fact, I think this question was asked and answered in Order 888(a) or something. So, since it's been so clearly dealt with by the Commission, we didn't feel like there was a mechanism really to file something that would say let us do it differently. Of course, I'm not a lawyer. There might be such a mechanism.

COMMISSIONER KELLY: Well, we allow changes that are superior to the Order. But it would seem, to the extent that that argument could be made that it's superior to that would be a good argument to make.

MR. PATTON: I'm going to have a conversation with our FERC attorneys this afternoon.

CHAIRMAN WOOD: As you know, we're contemplating looking at 888 more broadly, but I think if there are things like this that are really having an impact on service, not just trying to make things better but really fixing problems right now, we do need to hear about them. And, actually, in the context of a 205 or 206. I think that can certainly get done. We could fix things more broadly in a rulemaking, but moving forward on discrete cases to fix them as we're about to do when we talk about imbalance penalties in another items in a minute. We don't need to just hold off for some future event. Let's go ahead and fix what we've got problems with now.

MR. PATTON: Okay.

CHAIRMAN WOOD: Both of you all and we'll say that to this same gang next week or next time. That's what we want you to do is just identify imperfections in the market and then in the evolutionary manner get the fixes in places rather than waiting for a great big similar events like we've had with both of your markets in the last year. Let's do the incremental stuff, too, that doesn't get people to over exercised, but just view it as a gradual improvement in the customer service mentality. So be invited.

MR. PATTON: Okay.

Let me wrap up on the Day One markets just by summarizing our conclusions on how it operates versus the Day Two markets. Essentially, I think our conclusion is that the prior bilateral markets are substantial inferior to the markets that are currently in operation in MISO, the Day Two markets, for the following reasons.

First, the Day Two markets allow a much more efficient dispatch of resources and it allows the most effective generators with regard to any transmission constraint to be the ones that are ramped up to resolve the constraint. I think in the past we've shown you figures that say that through the TLR process we end up curtailing something like three times as many megawatts of transactions to try to solve congestion as you could redispatch if you were selective on what generators to redispatch, which is what the Day Two markets do.

Secondly, the prices now fully reflect congestion and losses, which is good in the short run and in the long run -- short run for operations and long run for investment.

Thirdly, the five-minute dispatch that happens in real time, in addition to the efficient benefits, I also think it brings substantial reliability benefits. We talked about this last year after the blackout that the five-minute dispatch is immediately altering generating levels within five minutes to reduce flow on facilities that are approaching their limits.

That allows you, No. 1, to operate the transmission system closer to its limits. And, No. 2, to have a lot more certainty about the relief you're actually going to get when a facility gets overloaded. TLRs are very imprecise. You don't know how much relief you're really going to get and you don't get relief for 20 minutes to an hour from the time that you call the TLR.

CHAIRMAN WOOD: I did notice, and hold my point, David, that Jim Torguson had a press conference yesterday and discussed the significant reliability change between the old market and the new. I think I hear Sudeen talking about he noted a transmission line in the region went out a few days ago. We were able to respond in about 10 minutes by changing the generation, redispatching around it, getting people to move the generation around. Whereas, in the past, using the TLR it could take one to two hours in many cases after having discussions with different control areas agreeing to issue the TLR and having it take effect. So rather than one to two hours we're now doing it in 10 minutes or less.

MR. PATTON: And I didn't even talk to him. Thanks, Joe.

It's amazing. When you look at any particular constraint, you'll see that there are often three or four or five generators that are far more effective than any other generation on the system to reduce the flow on that facility. And having an incentive compatible market that gets the generators to want to move their generation and help you relief the congestion in a five-minute timeframe is extremely helpful from a reliability perspective.

(Slide.)

MR. PATTON: Now we move to what's actually been happening in the first week of the market. The first figure I show you here shows you the day ahead energy prices in Wisconsin at the Minnesota hub and at the Synergy hub. And you'll see that, generally, the Minnesota hub is the lowest priced and the Wisconsin is the highest price with Synergy in between.

During the first three days of the market, the relatively small differences that you see between the Minnesota and Wisconsin prices are due to losses. The larger price difference that you see from April 5th through April 7th are due to constraints that are binding at various times over the course of the day. So you can see that we're finally seeing in more clear fashion the constraints that exist in the Midwest.

The reason I show you headroom -- what headroom is it's the difference between where generation is scheduled and its economic maximum. So when headroom gets small that means you basically have very little excess capacity ability to ramp up on your generators. So you'd expect an inverse relationship between headroom and prices. When headroom gets very small, prices should spike and that's essentially what you that we have lots of headroom in the middle of the night when base load units are staying on overnight and they're ramped way down. And, in the middle of the day, we generally have relatively low levels of headroom and higher prices.

The double hump that you see in the prices there is characteristic of the load in the Midwest. During the springtime there's essentially two peak a day. One at about 11:00 o'clock and one at 8:00 p.m. at night, generally, because the -- to the extent it's weather-driven, you're being more driven by the need to heat than you need to cool. Not very many people have their air conditioners on, so you don't see the midday peaks. But, secondly, you have other electricity usage that peaks at those times that are not HVAC-related.

(Slide.)

MR. PATTON: The next chart shows you the real time prices and you'll see the increased volatility of the real time prices that I was referring to. You can also see there, if you look closely, that we see more congestion in the real time on a shorter term basis. So you see some spikes in the price differences between the Minnesota and the one hub. You still see the same relationship between the headroom and prices that you saw in the other charts.

(Slide.)

MR. PATTON: To make more sense of the relationship between the day ahead and the real time prices, the next chart shows you on a daily average basis the relationship between those prices. You can see that what you expect is -- because there is always a lot of uncertainty in real time, so real time will tend to be significantly higher or significantly lower. What you expect is that over time the average prices in day ahead and real time will converge with one another with possibly the day ahead being slightly higher and that has generally been the case in here that prices have sometimes been higher and sometimes been lower.

I show you the virtual load. I'm going to show it to you in more detail in the next chart.

COMMISSIONER KELLY: David, before we get into virtual, do you have any data that could tell us how things have changed since market start up, for example, amount of imports, TLRs and maybe prices? Is it reliable data yet?

MR. PATTON: Yes. I think we could probably develop --

COMMISSIONER KELLY: Do you just have a sense now?

MR. PATTON: Yes. I'll show you the imports in just a moment, but the imports dropped immediately by about 2 gigawatts for the first few days and it's now returned to more normal levels. It dropped from 3 to 4 gigawatts down to about a gigawatt and a half and we're now up in the higher range. The prices haven't changed significantly in the bilateral market or the day ahead prices relative to what bilateral prices were prior to the market. It's been a little bit higher on a couple of days.

That's prices and imports -- TLRs. TLRs I don't have data on right now, but there have been a significant number of TLRs. MISO has a process. When it's redispatching to resolve congestion, to the extent that third parties are contributing to the congestion, they'll call a TLR to proportionally reduce the transactions flow over the constraints along with theirs. If they didn't do that, then what would be happening would be that MISO would essentially be redispatching and the loads in MISO would be paying redispatch so that non-firm transactions from third parties could flow without being encumbered by congestion. So it is the one area that I've seen where I think there's always going to be a continuing TLR process to try to coordinate third party activities with the MISO's use of the system. You don't see this sort of issue in the northeast where there's the flow from other people is not nearly the issue as it is here.

(Slide.)

MR. PATTON: Virtual purchases -- virtual load and virtual supply is very important in the day ahead market. It essentially allows the day ahead prices to reflect people's expectations about what's going to be happening in real time. And so what you should see is that when there's significant differences between day ahead and real time prices that you should see changes in the virtual purchases and sales to bring those prices together.

And, over the first week, you can see that, particularly, in the timeframe from the 5th through the 7th where on the 5th -- what happen on the 4th was we had a lot of volatility in real time, which is what caused the real time to be higher -- the day ahead to be lower priced than the real time. That expectation then carried over to the 5th that caused the day ahead prices on the 5th to be somewhat higher and the volatility cooled down in the real time market. And what you can see is that the virtual load purchases then dropped from the 5th to the 6th to the 7th and brought the prices back down toward convergence on those days.

(Slide.)

MR. PATTON: The next chart is probably even more revealing on what's been happening with virtual trades. When we started the market, I would say that, given the sheer size of the Midwest market, that quantity of virtual load bids and virtual supply offers was not impressive, given the quantities that we see smaller operating markets suffered a period.

You can see from April 1st to April 7th, the virtual supply increased by roughly 100 percent. That's below zero and the virtual demand increased by roughly 50 percent. so both have increased significantly and the line in this chart is showing you the net position of the virtuals. So you can see what the virtuals is doing is buying in the off-peak hours and then they become net sellers on April 6th and 7th in the peak hours, largely, to bring those prices together between day ahead and real time. So we want to see this trend continue.

One important policy issue for you all to think about is should be virtuals be allocated cost of reliability commitment cost and other types of costs. This issue has come up in New England and elsewhere. Although it seems equitable to charge virtual transactors for costs that other buyers and sellers in the market are incurring, I think it really hampers the efficient of the market to not have them be completely unencumbered. Because unless they see a price difference that is significantly larger than the potential charge that you're going to bill them with cost allocations they're not going to put in offers, which I think hurts everybody.

COMMISSIONER BROWNELL: David, this is great information and you would do California a service by making sure that the market participants there have it. I think there was one of the major utilities who was quite -- apparently confused about the value of virtual bidding into the marketplace. So it would great if they dealt with some facts. So, if you could make sure you Yakot Monsur -- his board and others -- get this information that would be helpful.

MR. PATTON: Noted.

(Laughter.)

MR. PATTON: In fairness, in places where they don't operate in base day ahead markets, I think some of these concepts are somewhat foreign. Thinking about virtual trading.

COMMISSIONER BROWNELL: Thinking about nodal pricing.

MR. LARCAMP: They've been thinking about for a long time.

COMMISSIONER BROWNELL: That's true. Thinking. Thinking.

(Slide.)

MR. PATTON: The next two charts look at physical supply and that's scheduled on the day ahead market relative to the real time market. This one focuses on the day ahead. Essentially, what it's showing you is the imports at the bottom that are scheduled to serve or that are cleared in the day ahead market. On top of that is that economic minimum. This is the minimum generation levels of all the generators that are committed in the day ahead market.

The next is the schedule generation above minimum and I'll talk about why it's important to distinguish between those to in a second. So the top of the blue -- the darker blue and the lighter blue -- is essentially how much generation and imports you're scheduling. Then there's headroom above that and then above that is the reserve range, which is the difference between emergency maximum and economic maximum. This is essentially the area on generators in the Midwest where we allow them to essentially take megawatts out of the market to supply reserves.

One of the issues is we're not sure that they're doing it to provide reserves and that's a data issue. We're working with the control areas so that they can tell us how many megawatts of reserves are being provided by which generators so we can match up which generators are providing reserves versus which ones are derating in this fashion.

CHAIRMAN WOOD: Those are being required by the 30 some control areas to be procured. They are actually procured at the direction of that -- the cost of that are born how? Just the generator has to do it?

MR. PATTON: That's a good question. I've been thinking about that.

CHAIRMAN WOOD: In the end market they're cost-based and then they're billed to -- like this would be regulation and other type reserves in the dark red?

MR. PATTON: Yes. Spending.

CHAIRMAN WOOD: Spending, operating.

MR. PATTON: And non-spending reserves.

CHAIRMAN WOOD: Okay.

MR. PATTON: The reality is a lot of these control areas are integrated utilities who have their own generation. The control areas have an obligation to meet their reserve requirements, so they're essentially self-providing it. I don't know how exactly it works where you have a large share of the generation that are merchant generators because a merchant generator would have to be paid something to provide the reserves I would think and I don't know who the control areas can bill for that.

Now what may be the case is they just claim credit for reserves. If I'm a merchant generator and I turn on my generations, that essentially provides some reserves. Whatever energy is not being dispatched at the top end of that unit maybe the control area is just saying I'm going to claim credit for that to meet my reserve requirement. That seems a little bit dangerous because if prices rise in the real time and we actually dispatch that generator it's no longer there for reserve. So I would like to --

CHAIRMAN WOOD: I seen Ron McNamara back there who we were with last week.

Ron, do you know the answer to that question?

MR. McNAMARA: We just incorporated the NERC rules so that LSC in each one of the control areas we have the same NERC responsibilities, whether it's a ECAR that remained, LSC would pick cost of that and pass it on to their customers. So they would have to show up in ECARs 4 percent extra in the day ahead and that may have a different one. So that's where this cost is recovered for generators. They would have to show the control area where the generation is on whatever the requirement of the control area is.

CHAIRMAN WOOD: How does that work with the LSC and the control area operator are basically the same people -- the same company?

MR. McNAMARA: Chinese walls.

CHAIRMAN WOOD: Great. All right.

MR. PATTON: Because there hasn't been a lot of generation divestiture it's not -- where you would have a problem is where you had a lot of merchant generation because then you'd be in a position where the LSC would have to go out and sign contracts with the merchants to provide reserves and it could be that there's not a large source of -- it could be that it's not competitive. In the Midwest there hasn't been a lot of divestiture, so most of the reserves would be self-provided by those obligated to have them.

CHAIRMAN WOOD: And so the yellow and then the dotted at the top of the chart?

MR. PATTON: Yes, the yellow is offered-but-not-taken, basically not economic.

CHAIRMAN WOOD: But those people are on the right side of the curve in the day-ahead market?

MR. PATTON: Yes, they're more expensive than the clearing price, which is expected, because April is not a very high-load month.

And then the dotted at the top is the capacity that's not offered, either because it's on outage or it's simply -- the decision is made not to offer it.

MR. LARCAMP: Does MISO or the control areas determine what's out on outage?

MR. PATTON: Well, there's an outage scheduling process whereby the generator is supposed to log an outage and the outage scheduler indicates the reasons for the outage. What you'll see -- and I think this is consistent, maybe, with what Joe has seen, given what he said about improvements to the outage scheduling process in PJM -- what we've seen pretty much everywhere, is that generators don't always report their outages, so that, you know, they'll go out of service without telling you.

And we did a comparison of -- MISO has had an outage scheduling system before the market went into place.

We did an comparison of the NERC GADS data on forced -- on outages versus MISO's outage data, and it looks to us like there's about a third of the outages that aren't being reported to MISO.

So, MISO's certainly not in control of outages, particularly forced outages, but we think it's something that needs to be monitored, and to the extent we can, we need to get participants to log their outages so that we know, particularly for reliability, we know when a generator is not going to be capable of responding, if we call them up and need to bring them online quickly or whatever.

MR. LARCAMP: Was there any experience of the forced or planned outages that were greater in this first week of operation, than a year ago, for example?

MR. PATTON: No, no, we didn't see a significant increase in outages.

COMMISSIONER BROWNELL: I think we need to pursue that further, the people that are not reporting. To me, that seems just an irresponsible act, and whatever the motivation, whether it's sloppiness or some other market motivation, why don't we pursue that?

I think that's quite dangerous, actually. It would be interesting --

MR. PATTON: Yeah, there certainly -- I think that in most of these markets, there is call for penalties that are -- you're aware that in the Midwest ISO tariff, we have market mitigation sanctions or penalties that I think -- I was very happy to see FERC take responsibility, you know, in terms of imposing the penalties.

But essentially tariff penalties related to exercising market power, so there has to be an impact to what the participant is doing, and that's appropriate for market power. But I think it's appropriate to have other administrative penalties for violating requirements of the protocols or the tariff that maybe have no market impact most of the time, things like providing information that's not correct, not logging your outages.

I think that would be a good idea, particularly in these capacity markets where we rely on unforced capacity as a measure of how much a generator can sell. There's really an economic incentive for them to avoid reporting forced outages, if they can avoid reporting a forced outage, because it de-rates their megawatts that they can sell into the capacity market.

CHAIRMAN WOOD: Bill and Dan, put that on the list.

MR. PATTON: The next figure basically zooms in on the scheduled generation, the top of the scheduled generation piece of the supply, the head room and the reserve range, and shows you day-ahead and real-time.

And I'm showing you two things here: One is where the forecast day-ahead load is relative to the real-time load. The average error in the first week here is less than one percent. That's very impressive.

The average elsewhere is something more like two percent. Now, this isn't a peak period, so it's easier to forecast when you don't have large weather uncertainty, but I think MISO is doing a good job on load forecasting.

You will see that the supply increases in the real-time. That comes from a couple of sources: One is reliability commitments that are made after the day-ahead. I didn't list this, but if anyone self-schedules generation after the day-ahead, that would increase supply in real time.

The dispatch of peaking resources, so, if they were offline in my prior chart but then they were called online, that would show up as scheduled generation in the real-time. And there has been a slight increase in net imports from the day-ahead to the real-time, so you can see that the top of the scheduled generation equals the real-time load, which, of course, is the balance you have to have.

Okay, and then I'm going to show you some charts now on the interchange between MISO and the outside world and the interchange between MISO and PJM, and then I'm going to wrap up with a summary of some results of the cost-based offering patterns.

The first chart that I'm showing here, shows you real-time net imports and day-ahead net imports. And what you can see is that the real-time net imports for the first, let's see, roughly four days, generally averages below two gigawatts on a day-ahead basis, which is significantly lower than historic net imports.

But it climbs from April 4th to April 7th, so that we, I think, go back to a more normal import pattern later in the week. What's perhaps more interesting is the fluctuation in real-time imports around the day-ahead, that the real-time imports are as much as a gigawatt and a half or two gigawatts higher or lower than the day-ahead imports.

This is very important, because the day-ahead imports are included in our commitment of generation to meet load, so if these real-time imports are fluctuating for reasons that have nothing to do with economics and they just sort of disappear in real-time, that could cause the MISO to set prices that are very, very high, you know, and create shortages.

So it's important that these external transactions, both in the day-ahead and in the real-time, are responsive to prices inside and outside the MISO, both from a reliability perspective and from a basic market functioning perspective.

And so we look at that on the ComEd Interface by looking at the price in PJM that they calculate for the ComEd Interface and the price that MISO calculates for the ComEd Interface, right there.

And what I show you in the bars below, is the day-ahead net imports, so net imports of less than zero are exports on net, and what you can see is that the PJM prices and the MISO prices, in general, have been fairly closely correlated with one another.

Where they started to diverge significantly -- for example, on April 5th, what you saw is that the pattern that we had been seeing of more than 500 megawatts of net exports, curtailed itself and became net imports, which, by April 7th, brought the PJM and Commonwealth prices into alignment once again.

So, you know, this is very encouraging evidence that the folks who are scheduling external transactions between the MISO and PJM areas, are responding to prices which will allow the markets to function efficiently and prevent reliability problems associated with non-economic import swings, net import swings.

What perhaps is more important is what happens in real-time, which I show you on the next figure. On the next figure, you can see that prices are -- the prices in MISO and PJM are clearly more volatile, and what's interesting is that participants are able to respond to the price differences they're seeing.

If you look at April 2nd, remember that on the previous chart, on April 7th, there was a consistent net export from MISO to PJM over the Commonwealth Interface, so it's something like 700 megawatts. What happened on April 2nd, is that the exports start at something like a thousand megawatts, but the prices in MISO are roughly $20 to $40 higher than PJM for the first few hours of the day.

And you can see that the exports are curtailed and by the afternoon, we're importing something like 800 megawatts from PJM over the Commonwealth Interface, and the prices in the afternoon, then, are in the same range of between $40 and $50.

So this is evidence to me that in the real-time, that people are able to adjust their imports in response to the price differences they're seeing, which is, again, very encouraging, because it means that the two regions, even though they're intertwined, are going to post prices that look more like a single market.

That is not to say that we can't improve the market-to-market interface, because I think there are improvements to the market-to-market interface that will allow us to converge better and allow us to optimize how much power is being traded between the areas, but I think the basic function looks encouraging.

Okay, the last figure I'm going to put up is the results of the cost-based offering requirement. FERC required that participants offer at cost --

CHAIRMAN WOOD: What page is that?

MR. PATTON: Page 30 -- that participants offer at cost for the first 60 days of market operations, and ask the IMM to administer a process to collect the cost-based information and to screen for offers that were higher than cost and report that to the Commission, which we've been doing.

This figure shows the results for April 8th, on the screen here, and what it shows is that -- the basic quantities, by the way, that look they have been in violation, have been roughly in the same neighborhood on each of the days. The extent to which they've fallen over time, has been due to improvements in the data that participants have given us, largely. They have been very motivated as of late, to communicate with us about areas where they think maybe our cost-based reference prices don't reflect accurate information about their units.

So, in any case, what you can see here is, I've shown you that on April 8th, more than 11 percent of all of the dispatchable offers in the day-ahead market, exceeded the cost-based requirement, that is, for the minimum generation piece or the dispatchable energy piece, and roughly 8.5 percent of the startup costs appeared to be in excess of the cost-based offer requirement.

That is for dispatchable resources. We also -- we screen everybody, but a lot of people self-commit and self-schedule their generation, and they're designated as must-run.

The MISO system will still have an offer in for them, but it essentially doesn't consider the offer, so roughly half of the violations, or a little bit less than half of the violations are on units that are in must-run status, so I've ignored those, because they are essentially not being used.

Then if you, though, look at the resources that are committed -- we have a lot more supply that's offered than we really need, so the -- if you're wondering, you know, what could affect the market prices, it would really be the offers of the resources that are committed.

If times were tighter, you know, it could be that units not committed, could affect prices, too, but, generally, it would be the committed resources. The violations on committed resources are less than three percent for both startup and for minimum generation and energy.

Then if you say, well, of those violations, what could really affect the price? A $20 unit bidding $23 when the price is $50, is having no impact on anything. A $100 unit bidding $115 when the price is $60, is having no impact.

The energy that you would think potentially could be affecting price, would be units that have costs below the market price, who are offering in above it, and, therefore, causing you to dispatch less of them and perhaps even setting the price at a slightly higher level.

When you employ that test, you're down to about 0.3 to 0.4 percent in the day-ahead market.

We computed the same statistics for units that are online in real time bidding into the real time market for a quick start resources that are offline or for the online resources. Those are basically the two categories of resources that considered the real time market and found that of all committed resources the violations are somewhere around 3 and 1/2 percent for minimum generation and energy. But, again, if you apply this test of resources that have cost below the price and are offering in above the price, you're at less than half of 1 percent.

So we have not concluded that any of these violations are significantly effecting the market outcomes, but they are, in our opinion, per say, violations of the tariff requirement.

CHAIRMAN WOOD: You'll be writing a report to us on that?

MR. PATTON: Yes. We have been giving you reports every day.

CHAIRMAN WOOD: I've seen them. I'm just saying something the world can see. I think it's real important for confidence in this market for people to know that if you don't play by the rules you'll have consequences pretty quick. And, if there is some middle ground there, then there's a place to work that out with you or with ONI staff. But this is what we didn't have in California five years that is the difference now and so we want to make sure that any sort of response like this that could have a market impact, even less than 1 percent, that maybe one hour that affects somebody a whole lot.

MR. PATTON: Yes. A couple of comments on that is our mitigation measures are still in place, which test for impact. And, during this initial phase of the market, all reference prices are cost-based so that to the extent of narrow constrained areas that we would be seeing an impact of larger than $36 a megawatt hour in any market at any location then the offers would be mitigated. And, in broad constrained areas when constraints are binding the threshold is $100 a megawatt hour. So, certainly, that's a pretty big threshold and it's going to be hard to break it. But, if a participant does have that kind of impact, then they'll be mitigated under the mitigation measures.

The difficult thing about the tariff requirement is it's not clear what the penalty is for breaking it and that would be something that you all would have to think about. We certainly are happy to make it clear who we think is in violation and by how much and give you some views on whether it's having an impact on the market, but we certainly can't do much beyond that.

CHAIRMAN WOOD: And discouragements. Good.

COMMISSIONER BROWNELL: So we'll assume that you'll identify those in violation.

MR. PATTON: Yes. We already are on a daily basis.

MR. HEDERMAN: Yes. They're getting it to us daily, Commissioner.

MR. PATTON: For you, confidentially. I think the idea maybe a good one to have something public. I don't think we can name people because we have tariff requirements to maintain confidentiality of offerors, but I think we can probably report on aggregate levels of violations.

COMMISSIONER BROWNELL: So, David, let me just ask the sum-up question. We saw behavior in the marketplace pretty early in the game that you looked at that would represent probably people being conservative as opposed to people manipulating the market. That's settled out over time. We see for the first time that there is a price to pay for under-building your system as in Wisconsin. We see virtual bidding playing an important role and you are comfortable that you have sufficient data in most areas to quickly analysis what's happening in the marketplace, so, once again, we don't run into a California where we're trying to figure it out now four years, five years after the fact. Is that fair to say?

MR. PATTON: That is fair. Yes. We're getting most of the data in real time. In fact, some of the primary reports that we are monitoring are updated on a 30 second basis, so we know pretty much immediately what's happening, which is really critical from the perspective of not being behind the eight ball once something has happened and you're trying to catch up and figure out what's going on.

Most of the time, before things have an impact, you can see that something is happening that could have an impact and so you can start trying to address it ahead of time. There are some areas where I think in the longer terms there's some potential for significant improvement. I think the market-to-market interface could be improved. I think in the longer run there's a real question about phasing in things like reserve markets and capacity markets in the Midwest. Because in those areas where you need generation, you're going to have a problem relying solely on the markets that we currently have -- the same sort of problems that Joe's referring to in New Jersey, the same problems that you've seen in other markets.

So I think there's room for improvement, but we're very encouraged by the initial operation. This is clearly the most massive undertaking we've witnessed in one fall swoop and to get markets in place in an area where there has been no power pool in operation and to have the kind of coordination with PJM that was required immediately and have it working. So we're very happy.

COMMISSIONER BROWNELL: And, contrary to expectations, reliability has not only not been degraded, it's been significantly improved. I'm restating the obvious for those who never hear it the first time.

MR. PATTON: It is a fairly basis idea, but I don't know how you can get pass the conclusion that if you have generators offering flexibility to you and on a five-minute basis you're optimizing the output of those generators in response to constraints on the system and so forth that that just has to be more reliable because you get more predictable response when you have a constraint that binding and much quicker response than you could get through any other system that I can think of.

The one thing that concerns me a little bit is just the way that the reserves are being handled in the Midwest. I think we clearly need more information from control area operators on the units they believe are holding reserves. We are monitoring it and in some cases it doesn't look like units are actually holding out of the market to provide reserves. It looks like they are being offered into the energy market. So, if they were to get dispatched, some control areas would have little or no reserves left if then there was a contingency generator that tripped out and you needed to call on their reserves.

So I think we need more information passed between the control areas and MISO and myself on what reserves are being provided from which units in order to make sure that works probably, but I think we can get that in place before summer when it would be more critical.

COMMISSIONER BROWNELL: I think we have a number of follow-ups that we need to make. That would be among them. And I think one of the things that we've talked about this morning is we expect the market monitors to be aggressive about identifying rule changes or gaps so that we can respond quickly to that. But I appreciate the work that was done, both by PJM and MISO. I know that we will continue to work on seams issues. I think that's important. That's important throughout the country, but we're glad it went so smoothly and that you proved us right. Thank you very much.

CHAIRMAN WOOD: You probably don't have it now, David, but similar to what Joe did -- kind of a year-to-year comparison with maybe the fuel issues taken out would be helpful for us in analysis of this market, but also thinking about it more broadly to look at the year-to-year comparison after maybe a little while. The first 10 days is a bit ambitious, but after a few months or something maybe look at this time last year. I don't know if you can weather normalize, but just to see if there's anything similar to what the Joe Etos study had that came out of the Department of Energy and released around Christmas that showed the benefits looking at just sample hours throughout the year of using across the footprint dispatch as opposed to utility-specific dispatch. He reflected energy savings around 20 percent, but it's kind of hard sometimes to see that if we don't have somebody like you whose job is to really look at the cold hard numbers. So, if you could put that on your tick list to look at year-to-year comparison between dispatch costs outside of an LMP/pool environment. And then now that they've got one now to see if, in fact, the study that the Department of Energy did, in fact, is playing out.

MR. PATTON: Okay.

It's important to recognize that you won't always see -- we have looked at some fuel price differences because prices have been clearing 15 percent higher than they were clearing last fall and we've seen that that's generally tracked the gas price increases.

One thing that I would want to manage your expectations on price effects of going to LMP because one of the benefits of going to a day ahead real time market is that you rationalize the commitment of generation. What often happens in sort of decentralized markets without a day ahead market is that people tend to over commit their resources because everyone is committing to meet their own resources. Nobody's relying on other people's. And, when you put in a day ahead market that commits just the right amount, you can end up with higher energy prices because you have less supply online, but the prices are more efficient because you're making better commitment decisions. So it often is a little complex to try to piece those things together and say what's the net. Sometimes the energy prices won't change much, but maybe you're saving yourself a lot in commitment costs by not bringing on so much generation every day.

CHAIRMAN WOOD: So that would be the total cost to society actually would be down, but not reflected in a given unit per time unit price.

MR. PATTON: Correct.

CHAIRMAN WOOD: That's what it's all about -- getting a more efficient system and save customers money.

All right. Any questions for Mr. Patton or Mr. Bowring?

(No response.)

CHAIRMAN WOOD: David, I think we'll see you again the next open meeting. But, Joe, again thanks and best wishes to all of you all.

MR. BOWRING: This is our last state of the market to you. It's been a pleasure reporting to you. Thank you.

(Laughter.)

CHAIRMAN WOOD: All right, folks. Let's roll on. Thank you, gentlemen.

We'll have the next report.

MS. SALAS: The next item is A-5. This is a report on information technology guidelines for power system operations organizations. It's a presentation by Joe McClelland and Dave Turner, who is an executive of Gestalt.

CHAIRMAN WOOD: I'm going to say, though -- don't walk away, Linda. I just put on my glasses and saw you were here. I just want to welcome you back home and tell you we're glad you're here and I know the last report had to be pretty gratifying to you since you, before any of us got here, played a role in kind of getting them out of the harbor. Welcome back.

COMMISSIONER BROWNELL: The long awaited report.

MR. McCLELLAND: Good afternoon. We couldn't help noticing that the first two speakers were Joe and Dave. We made certain we maintained the seats and that's actually a pretty handy illustration for what will come later, which is avoiding customization and using off-the-shelf solutions.

(Laughter.)

CHAIRMAN WOOD: We didn't even have to change the name tags.

MR. McCLELLAND: Good afternoon. My name is Joe McClelland and I'm the Director of the Division of

Reliability. With me today is Dave Turner, Energy and Utilities executive of Gestalt, LLC. Not with me at the table today, but having made substantial contributions to this report are Regis Binder, Ton Long and Frank Masento from the Division of Reliability and John Genrich from OMOI.

As has been recognized in prior staff reports to the Commission, the cost and management of information technology projects or IT projects can and does have a substantial impact on the power system operator. These IT projects and their work products, however, are critical to the success of these organizations by providing them with, among other things, supervisory control and data acquisition systems for reliability, energy management systems, distributed management systems, financial and other management systems.

In fact, one of the core findings of the August 14, 2003 blackout report cited a lack of situational awareness by the system operators. Of course, such situational awareness is impossible without adequate and functional IT systems. This is one of the three Ts of the blackout report -- tools, training and trees. But what IT functions are necessary for the power system operators and how can IT projects be justified, managed and implemented?

The Commission has been concerned about reports of IT project cost overruns as well as reports of excessive or inadequate system investments. In order to help address these questions, Commission staff has completed a study using Gestalt to explore the IT needs of the transmission owners and operators, investigate recent IT projects to determine elements for success or failure and form recommendations to improve new IT projects. The result of this effort is the staff report for information technology guidelines for power system operators. This report is meant to serve as a resource to regulators, the industry and its stakeholders and will be posted on FERC's website and provided upon request.

(Slide.)

Working through prior projects Gestalt found that for 2004 only 34% of IT solutions succeeded. The rest either failed completely -- that's representing 15 percent -- or failed substantially, 51%, meaning they failed to meet schedule, budget, or functionality commitments. Gestalt found that the electric industry is no more immune to IT project failures than any other industry. These statistics actually represent an improvement from prior years. For instance, in 1994 32% of IT projects failed completely. The key to continuing this improving trend is to aggressive manage the projects from inception through completion, recognizing the potential for cost overruns at every stage and the dependency of the organization on the end product.

The study found that project failures for the most part can be eliminated by keeping to four key elements. The first: set clear expectations/specifications and establish realistic schedules. At the very beginning, determine and quantify the need for the project. Is it necessary and does it address a particular reliability market or management need? Compare this solution with what others have done in their applications to address the same need.

Number two, develop common architectures, standardized technologies and avoid expensive customization by re-using applications. Determine what buy versus build options exist, recognizing that it is usually better to buy an existing product versus develop a new one. Again, what have others used and how are their solutions working? Can they be used for your application?

Establish standardized IT governance project management, technology development, and vendor management. Necessary to this governance is to attract and retain qualified and experienced IT project managers, supplemented with outside expertise if necessary, writing tight project specifications and using existing applications wherever possible. And the critical aspect: internal corporate oversight of IT should differ little than non-IT corporate oversight.

COMMISSIONER BROWNELL: Joe, can I just interrupt for a second and ask a question. And maybe, Dave, you're going to get into this, but when we talk about established IT governance, project and vendor management, I hope that at some point we're going to discuss what that means. For example, we know delays or incomplete work up front is one of the major drivers of cost and I think that's an important lesson learned. So if you could either speak to it now or, Dave, speak to it in your presentation.

MR. MC CLELLAND: I'll take the first shot and, Dave, you can jump in.

In fact, Nora, that's true. And the very first goal is that you set clear expectations and write clear sp3ecifications and then you set realistic project deadlines. A violation of any of those aspects -- IT project management is really no different than any other project management for complex projects. You need to see what the specifications should be and they've got to be tight and then you've got to match that up against the project deadline and then you've got to stay after it. But even prior to that is the inception of the project itself: is it necessary? And these aren't questions that have to be asked by experts in the IT business, they're just asked by the stakeholders and the regulators and the board members. Is this necessary? What have other folks done to address this issue? There are other folks that, we're certain, have had to address this for the market or for reliability, what have they used and can we use their project or their end product. If you can do that, it's a lot easier to set the specifications and then the project deadlines and timelines.

MR. TURNER: I think actually Joe hit everything pretty succinctly. When we're talking governance and project management and technology development and vendor management processes, we're talking about putting in standard processes, business management processes that would be used in any industry and then making sure that they're followed, standard reputable processes that -- and tools for folks working those processes to use to track their performance.

COMMISSIONER BROWNELL: Well it took a failure rate like that which you've identified, apparently those IT governance processes aren't in place.

MR. TURNER: You know, in some cases they aren't, in many cases they're improving. At places in the report we talk about the improvement from '94 through 2004. Yes, there are many places where they need to be put in place and more rigorously followed.

MR. MC CLELLAND: I think, Dave, you had a specific example of an application?

MR. TURNER: Well, you know, there are places where today you can see technologies being implemented more effectively. I think if you went and talked to Joe Bowring and the guys at PJM, integrations of AEP have occurred more on schedule, on time than they expected. ISO New England's implementation of a standard market design went a little smoother. New York ISO is implementing some new technologies that are working well. But it's taking time for these things to evolve and it will take time to see the real fruits and benefits of that effort. We need to continue some of the standardization initiatives that are going on right now.

COMMISSIONER BROWNELL: So is one of the

questions we should ask as regulators when we're looking at market design proposals what, for example, the fact that it's slightly different than the neighbor is going to cost and that -- we talk about standardization and then nobody wants standardization but in fact no one measures the real cost of doing it just a little bit differently so you can't do the off-the-shelf solution.

MR. TURNER: Absolutely. Those changes, the customizations as we call them tend to cost a significant and add a significant to what we call the out-of-the-box or off-the-shelf cost of some of these systems. We had an example of someone who bought an EMS system out of the box and implemented it for $9 million as opposed to tens and twenties of millions of dollars that others spend on that same.

MR. MC CLELLAND: And the actual customization in that case wouldn't have added -- I mean, incrementally --

MR. TURNER: Typically it doesn't add incremental benefit to outweigh the incremental cost.

COMMISSIONER BROWNELL: So stakeholders probably ought to be asking those very same questions.

MR. MC CLELLAND: And it's very important that when they ask those questions they're prepared to consider the answers as far as the market design or the reliability design. It's important for the entity that's involved to define what that incremental adjustment is as far as timelines, new technologies, customization, and try to attach some price tag to that customization.

Finishing the third point, in fact a recent MIT study of more than 200 public companies revealed that companies without -- with established IT governance structures earned on average 20% more than companies without.

The last is requiring information technology best practices. Best practices can be encouraged by the right questions from regulators, board members, customers, and stakeholders. Such questions from these groups include: is the project necessary? How is the investment justified economically? What are the other power system operators doing to address the issue and why can't we used their solution? What is the exit strategy if the project fails? How will the vendor be managed. And is the supported function completely mature, and so forth.

And just to take you back quickly to how will the vendor be managed, there are parallels with other projects. For generation projects that are complex and occur infrequently, many times the owners will retain owners' engineers, industry experts on a retained basis to evaluate, you know, the specifications to be involved with the initial project setup and then to watch the performance of the vendor during the process. This same process could be used for IT projects.

The report details these elements and provides some specific examples of successful projects within the power system operator business segment. At this time, I'd like to turn the presentation over to Dave Turner for his comments about how the report was researched and assembled.

CHAIRMAN WOOD: Thanks, Joe.

MR. TURNER: The information presented in this report was assembled by a team of power system operations and markets, utility industry and information technology professionals from Gestalt, as well as several independent technology consultants. The team developed and compiled the information based upon years of power system operations and utility industry operations and information technology experience. The team called upon personnel, personal experience, extensive research, and expert opinion to develop the structure and content of the report. We reviewed publicly-available data and reports to verify our assumptions and test recommendations. We met numerous times over a two-month period to discuss concepts, develop content, and edit individual results. The initial thoughts in draft documents were reviewed with several key industry stakeholders to ensure that the results and recommendations were clear, actionable, and realistic. The final draft of the report was reviewed and edited by two experienced IT professionals prior to submittal.

The report provides a comprehensive overview of power system operations technologies and IT management best practices and should be reviewed in detail to gain a full understanding of the technology management issues and recommendations.

Next slide.

The team was comprised of professionals with information technology, power system operations and markets, utility operations, and business management experience and expertise to ensure that each issue would be looked at from multiple perspectives. All too often critical ideas are missed or concepts rejected because the team has only an IT, operations, or financial perspective. We purposely staffed the team with multiple professionals from differing backgrounds to avoid that type of group think. The result is a balanced perspective which provides realistic actionable recommendations.

The team included a group of seven contributors and two reviewers. The contributors authored individual sections of the report according to their expertise and experience. The segments were reviewed and coordinated by mutual consent of the team members to assemble the first full draft. The reviewed then read each of the sections in the context of the whole report to be certain the report was clear and actionable.  The result is a comprehensive report that we hope industry, stakeholders, and regulators will find to be a valuable resource for IT evaluation and management.

Thank you for your time and attention today. This has been an exciting project to work on and we're looking forward to addressing any questions you might have.

CHAIRMAN WOOD:  Dave, thanks for coming.  Joe, thanks as well.  This is something we started over a year and a half ago and I'm pleased to have you all kind of translate it for us.  It's a very dense, comprehensive report and it's what we wanted and what we needed.  And it's my intention to get this report to the people that we regulate, both RTOs and individual utilities and certainly their board members I think would benefit from this information as well.

As we see coming through here, not just on the RTO stuff, but everywhere and particularly now more on the reliability side as the control areas and the reliability coordinators are making the needed improvements to their tools, as well as the training in the trees, but that the tools themselves -- that's a big-dollar item and it's one of the issues that we went over to talk to Senator Craig about on the cybersecurity angle, making sure we don't throw a lot of money out after good ideas if they don't have kind of a comprehensive vision about what they're trying to solve. So so many things play right into this and this is actually I hope for us for many years to come a good touchstone about what we should look for. Because we're not going to -- on the regulatory side of the fence, we're not going to know that this is the best solution. What we can do is force people to go through a thought process and an organizational process that we feel confident would lead to, you know, what in effect is a just and reasonable rate for charging for that service. So thanks for giving us a took we didn't have and a thoughtful one at that.

COMMISSIONER BROWNELL: Can I just add, you made a point I'd like to jump on and that is that there is a nexus which Joe has reminded us of frequently between this kind of discipline, between security and cybersecurity, and I would hope we'll focus more on that, including identifying control room technologies that are going to be required to have a reliable system. I know NERC has been working on that. Maybe we could work on that, too, so that we don't have to wait. I think we're vulnerable in that regard.

The second thing is -- because I know I've been the ultimate nag on this issue for 3-1/2 years -- this should be required reading for board members, for stakeholders, as well as the management. And one of the questions I think we should ask when we're reviewing the RTOs, particularly, is what are the best practices and how are they being implemented, what's the organizational structure so that we can avoid some of those cost overruns that candidly we've seen everywhere. We haven't seen then in the utilities because we just don't know but I suspect they're there, too.

Thank you.

COMMISSIONER KELLY: Dave, I would just like to add my compliments to you on the preparation of this report. Perhaps I should hesitate to say that as I looked at the cover of it and thought information technology guidelines and the heft of it, I wasn't sure that I was going to be able to get through it without taking a little nap, but it's very well written --

MR. TURNER: It's had that effect on me as well.

COMMISSIONER KELLY: Not only is it well written and well organized, but it's fascinating and the information in there kept me awake. The statistics that you reveal are also quite telling. I had no idea that the failure rate for IT systems was so high. I think it explains in large part why we have some of the problems that we have here, that land up on our desk.

MR. MC CLELLAND: I think that's a well-kept secret across industry.

COMMISSIONER BROWNELL: Before you go though I have to ask you, how did you firm get its name and are you headquartered in California?

MR. MC CLELLAND: We're headquartered in King of Prussia, PA, and our CEO is a wanna-be philosopher. That's where the term comes from.

COMMISSIONER BROWNELL: We'll remember you.

MR. MC CLELLAND: Thank you, I've enjoyed it.

SECRETARY SALAS: The next item for discussion is A-4. This is long-term transmission rights in organized electricity markets. It's a presentation by Budd Earley, who is accompanied by Udi Helman, Sebastian Tiger, Harry Singh, and Jeffrey Dennis.

MR. EARLEY: Good afternoon, Mr. Chairman, Commissioners. In response to concerns raised by some market participants, this Staff team is assessing the need for long-term transmission rights in RTO and ISO electricity markets. The team members at the table with me have already been introduced. Other members of the team are Roland Wentworth, Dick O'Neill, Partha Malvadkirk, Dave Mead, Richard Mabry, and Emilie Bartholomew -- though of OMTR -- Dave Withnell and Marsha Gransee of OTC, and Eric Say of OMWA.

An important cost of transmission service is the congestion cost that customers incur when, due to the physical limitations of the grid, they are unable to obtain energy from the lowest-cost generation resources. Under traditional grid management, these costs are generally socialized. In markets with locational pricing, these costs are made explicit. In such markets, participants can hedge against congestion costs by holding financial transmission rights, or FTRs, which are allocated to historical users of the grid either directly or indirectly by rights to FTR auction revenues. Currently the longest term of FTRs offered in any of the RTOs or ISOs for the use of the existing transmission capacity is one year. A load-serving entity has a long-term right to request transmission rights year after year, but there is no guarantee that it will receive all the rights for which it is eligible. On the other hand, if an entity expands the grid, it will receive multi-year financial rights created by that capacity, although the rules vary by RTO or ISO.

The issue presented to the Staff team is whether customers should have some way to obtain a congestion cost hedge for periods longer than one year. The adequacy of long-term transmission rights is also an issue in markets without locational pricing, but the team believes that there are unique issues in markets with locational pricing that may be best addressed separately. Addressing the more general issues associated with long-term rights is more

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appropriately the subject of a comprehensive review of the Order 888 tariff.

This team will attempt to address the following questions: What issues arise from the lack of long-term rights and how widespread are any problems? What are the impediments that RTOs and ISOs face in specifying and awarding long-term transmission rights. And what steps should the Commission take to address the problems identified.

The team has been conducting informal outreach. We have met with representatives of the major stakeholder groups identified on the slide, as well as the RTOs, ISOs, researchers, project developers, and the financial community. We will be talking with NAREC soon as well.

Based on our discussions so far, the team offers the following observations and issues to be addressed. The first general observation is that interest in longer-term FTRs -- that is, multi-year FTRs -- varies depending on the type of firms seeking FTRs and the design and history of each RTO market. Essentially, in RTO markets such as MISO, for example, where participants currently believe that the annual allocation of rights will yield uncertain results from year to year, there's more interest in locking in multi-year rights. This is of particular concern to small utilities with generation that is remote to their load and

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hence reliant on FTRs to hedge congestion charges over time. Such utilities also feel that uncertainty over annual FTR allocations will hamper their ability to finance new and generally remote generation projects. There appears to be less interest in long-term FTRs among entities with larger and more diverse generation portfolios that give them a greater ability to manage FTRs and congestion risk. In addition, load-serving entities in retail choice states typically are managing shorter-term energy contracts and may prefer that congestion hedges are readily available in annual and monthly terms.

The second general observation is that the details of how long-term transmission rights are specified, as well as the uncertainties about the future going out five, 10, or 15 years can make it difficult for the RTO to offer a long-term right with value and hedging properties that satisfy all participants equally.

One major uncertainty affecting the properties of long-term rights is that changes in the transmission network over time affect the location and duration of congestion.

How such changes affect the revenues from such rights is, in turn, related to details of how the rights are specified, including their duration, whether they are option or obligations, and whether they guarantee full payment or not. We also heard from our discussions that other sources of

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uncertainty about such rights are the changes in regulatory policies of market design that we see in the RTOs and ISOs.

As to next steps, we encourage further input from those that we have not yet talked with, as well as from those that we have. The team plans to issue a discussion paper in early May, before the May 13th technical conference in Charleston, West Virginia. The paper will discuss Staff's assessment of the issues and request comments. Most important, the paper will ask for suggestions regarding how participants in organized markets might secure long-term rates at known prices. The team will assess the comments and make recommendations regarding how to proceed.

The team will be happy to answer any questions from the Commission. Thank you.

CHAIRMAN WOOD: Thank you, Bud. I wanted to just have Bud report on this today. I know this is an issue of concern in the energy bill discussions down the street and it's been one that was raised to us back, certainly over the last few years but in a more concrete way by the APPA discussion piece last fall.

And what I really do want to encourage here is Bud's last point. We're looking for workable solutions here, and those have to come from the people who have to live with it, and that includes the market participants, both buyers and sellers, as well as the managers of these

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regional marketplaces. And so I'm going to look to some leadership from them and, quite frankly, not just legislative language that tells us to go and do just the same thing, we're doing that. We need to do that now. And we're happy to get a pat on the back for doing that, but we need to solve this thing and figure out a good solution now.

But I did hear some caveats certainly on Udi's layout of the different findings here and one is opt for long-term right with value and hedging properties that satisfy all participants equally. The good Lord himself probably couldn't have done that, so I do think that there's going to need to be some flexibility as to how these things get addressed, perhaps market by market, but just a conceptual approach would be very useful here.

The thing I want to avoid is what we just talked about with the last guys up here, the first panel today, is, you know, getting some real efficient utilization of the grid by the way it's being dispatched now, both in the day one market but particularly in the day two market that we just talked with David Patton about.

And I don't want to see, you know, anything that we do here really just in effect take capacity back off the market to where it can't be utilized and you've got a lot of people being deprived of utilizing transmission because of some of this. I think it can be worked around but I want to

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just kind of put a marker down that that's a very hard-fought gain that we've made in the open access era is to get more customers utilizing the existing grid and then I think the fight we're facing now is getting that grid expanded to meet the needs of further customers. Let's make sure that as we do that we don't ever kind of take some steps back. As some have feared here, I think it can be worked around but I just want to put that out there as a marker that I'd like to make sure it gets fixed.

COMMISSIONER BROWNELL: I'd like to emphasize some of your comments in creating realistic expectations, because maybe God could but I don't know that we can and I think somehow there's an expectation, there's a magic wand that can be waved with a silver bullet. I think that the fact that systems are just physically dynamic over time makes this a challenge that we have an underbuilt system in many parts of the country makes this a challenge. I think it's interesting, actually, as markets have evolved in the northeast this has become less of an issue so there may be some lessons learned there. And I hope that we will get suggestions and not just broad rhetoric fix it, fix it, fix it, because I think the very people who are suggesting this is a problem need to demonstrate how it's a problem and how their solution matches us.

I think there's no easy fix here and I think we

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need to be realistic and honest about that. And it may be market by market, although then you have yet another set of issues you have to deal with. And maybe we need to get experience over time in some of these markets to see how much of an issue it really is in the long term.

So I just wanted to say God love this team who has really, I think, been struggling with some of these issues in legitimately identifying some of the barriers to the quick fix. We're a nation of quick fixes and this one just -- this isn't one of them, unless, I don't know, there are a lot smarter people than I am out there, maybe there is. So thank you.

CHAIRMAN WOOD: Thanks, team. We'll see you soon. White paper out before -- discussion paper out before the technical conference in Charleston.

All right. Wind team?

SECRETARY SALAS: The next item for discussion is E-4. This is imbalance provisions for intermittent resources and assessing the state of wind energy in wholesale electricity markets. This is a presentation by

Matthew Deal, who is accompanied by John Carlson, Vic Coulter, Jignasa Gadani, Bill Longnecker, Bruce Poole, and Jeffrey Sanders.

MR. DEAL: Good morning, Mr. Chairman, Commissioners.

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E-4 is a draft Notice of Proposed Rulemaking that is designed to encourage the development of wind and other renewable resources by removing barriers that affect intermittent resources ability to compete on a level playing field with traditional generation sources.

This draft NOPR is the result of an outreach process by the Commission which began with a conference in December 2004 to assess the state of wind energy in wholesale electric markets. It continued with a formal comment period and informal Staff outreach.

During this process, we heard that intermittent resources, particularly wind generators, are interested in availing themselves of the open access transmission tariff for opportunities to make sales beyond their host utility but are hesitant to do so because of the application of imbalance provisions that were designed to apply to dispatchable resources. These imbalance provisions were not designed to apply to intermittent resources that are weather driven.

The draft NOPR proposes to standardize under the pro forma open access transmission tariff generator imbalance provisions which apply to intermittent resources. Specifically, this new schedule establishes a plus or minus 10% bandwidth with a minimum of two megawatts for intermittent resources and allows generator imbalances

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within the stated bandwidth to be settled at system incremental cost at the time of the imbalance. Energy outside the bandwidth would be settled at 90% of system decremental cost for energy generated in excess of a schedule and 110% of system incremental cost for energy generated below a schedule.

The draft NOPR also reiterates that the permit transmission customers to modify their schedule up to 20 minutes before the hour. Under this draft NOPR intermittent resources will be assessed the lesser of the generator imbalance charges pursuant to this schedule -- to this new schedule or any existing generation imbalance provisions under the OATTs that contain them. The draft NOPR also clarifies that the existing Schedule 4 energy imbalance charge would continue to apply to transmission customers only for deviations in scheduled load, as intended in Order Number 888.

The draft NOPR seeks comments on various aspects of this proposal, including the proposed generator imbalance bandwidth and the pricing provisions, the technologies to which this proposed rule should apply, and how to implement the NOPR. The draft NOPR also seeks comment on the additional proposals submitted by intervenors identified during the outreach process.

The draft NOPR before you complements the

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Commission's January 2005 NOPR in Docket RM05-4, where the Commission proposed uniform interconnection standards specifically tailored to the technical requirements of wind-generating plants. That proceeding is still pending before the Commission.

Actually, before answering any questions that you would have, I'd like to take a moment to mention the additional team members that aren't seated here at the table today. The team also included Kristin Connolly, Annette Marsden, Norma McOmber, Dick O'Neill, Susan Polonay, Peter Radway, Jamie Simler, Roland Wentworth, and Dave Withnell, in addition to many other staffers that served as consultants in hallway conversations and sounding boards for various other ideas that went into this draft before you.

And with that, thank you, and any questions?

CHAIRMAN WOOD: Thanks. I remember walking out the end of the day in Denver at the technical conference we had out there on wind energy issues and one of the punch items that really came out of that and this was pretty much at the top of a lot of people's lists and I'm really pleased that we could go through the outreach process and get something out there that people could react to in a concrete way as quickly as we did.  So thank you for the effort that you all did to really demonstrate our ability to respond on a key issue, particularly in certain parts of the country

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where it really means a whole lot more than maybe other parts of the country. But this particular issue could have a panel, I think we could have a substantial impact on the development of intermittent resources, not -- primarily wind, but I think we're open to that, certainly we asked the questions on that ground in the NOPR across the country. So that's a good thing to do. So good on you.

COMMISSIONER KELLY: I want to thank you, the Staff in particular, for all the midnight oil that you've burned. It's been just about four months since we were told in Denver, at Pat mentioned, that this was one of the most important issues to the wind industry and to the public. And that's fast turn-around to be putting out a proposed rule on it. So thank you very much.

AWIA told us that schedule deviation policies -- quote -- "create discrimination in the wholesale market." And that's because the intention of the penalty for imbalance is to influence a generator to keep hourly output matched to schedule production. Well, the source of the deviation in the case of wind power is the changing weather and it's not influenced by the threat of penalty.  So I think it's particularly appropriate that we take these steps today because it certainly does appear that the imbalance penalty policy may impact the ability of an intermittent generator to avail itself of the open access transmission

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service. The NOPR appropriately asks a number of very detailed questions that I hope we have many commenters respond to regarding how both energy imbalance penalties and generator imbalance penalties should apply, if at all, to intermittent resources.

And Matt, you mentioned the difference and that there was a difference in our NOPR. I'd like to emphasize that, but correct me if I'm in error as I attempt to explain it. But there are imbalances that come about for two reasons: one is that the generator has failed to match his output to his scheduled production, and that's a generator imbalance. And that's what our NOPR deals with --

MR. DEAL: Correct.

COMMISSIONER KELLY: -- penalties associated with that.

The other imbalance we call an energy imbalance, is an imbalance that arises because of the variation in load, expected load. And this NOPR does not propose to change anything on that end, is that correct?

MR. DEAL: That is correct.

COMMISSIONER KELLY: Okay. Thank you.

I think that we have taken a great step here and I'm excited that we are taking action so quickly to help advance the integration of intermittent resources, particularly wind, into the grid, given that the public is

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particularly demanding of it. There are 19 states and the District of Columbia that have renewable portfolio standards in place, have signal their intent as a matter of state public policy to have more wind integrated into the grid, and Congress has consistently implemented a production tax credit for the first 10 years of wind production, so I'm glad that we can be part of this national effort to better facilitate renewables in our country. Thank you.

COMMISSIONER BROWNELL: I just have a couple of questions to make sure that I understand what we're doing or what we're asking here. There have been those who have said this kind of a proposal amounts to a subsidy of wind, but as I understand it wind is paying their fair share of the incremental cost of the system; what we're talking about is defining the deviation costs essentially. Is that correct? This isn't fundamentally amounting to some kind of a subsidy.

MR. DEAL: I think that would be a correct assumption -- or a correct statement. Wind isn't looking for a free ride, as I would assume neither are any other intermittent resources. The NOPR addresses that, talks about that, says that if there are any additional costs that someone thinks wind is putting on their system or another intermittent resource that we would entertain proposals for adequate recovery so that wind or another renewable would

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pay those costs.

CHAIRMAN WOOD: It's getting rid of the penalty aspect of it, because you should penalize something for behavior you don't want to have happen. But this is behavior you can't affect because it's, you know, the laws of nature. But that's just making them pay their fair cost for the incremental -- and then there's a penalty kind of a little bit if it goes way outside the bandwidth. But it's not, I don't think, disproportionate.

COMMISSIONER BROWNELL: I agree with that but I think that there are those who are still of the misimpression that somehow there's an effort to subsidize wind and I want to make sure that's clear.

We also talked about -- or the AWIA folks and others brought up the opportunity for monthly netting. And so what I think we're talking about is realtime costs assessed but the deviation be netted over the month. Is that -- do we address that issue or is that at least teed up as a question?

MR. DEAL: It's teed up as a question. There are several proposals that were listed as intervenor comments that we see comment on.  That is one of them.  People raised issues on both sides of monthly or even weekly or any other variation of netting.  Basically we were going with hourly settlements and asking comments on it.

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COMMISSIONER BROWNELL: Okay. These charges, as I understand it, appear depending on kind of what the arrangement is on the OATT or in interconnection agreements. Is it appropriate on a going-forward basis to say we really don't want additional charges in the interconnection agreements? I'm not suggesting for a moment that we retroactively impose that, but would it make more sense to kind of have it standardized in the OATT so it's clear to people what these charges are?

MR. DEAL: I think it would be a good idea. We're not mandating it or we're seeking comments on that, but we're also looking to have the proposal here, if adopted, to become a model for any type of generator imbalance provision that would be contained in either aspect. We could look at that further on and see if it should all come into the OATT or not.

COMMISSIONER BROWNELL: It might be worth seeking comment on.

And finally, do we -- are we thinking that this addresses pretty much all of the issues of imbalance charges that have been raised for this resource or do we think maybe there's something more out there that we need to hear about, in which case let us hear about it. Because I think you're tried to really respond to the issues that have been identified so far, is that correct?

MR. DEAL: Yes, we've undertaken the Staff outreach and I know certain entities have been in each of the offices discussing the issue. We think we've taken great strides to alleviate some of the concerns. More than likely there might be some additional concerns that someone will bring through the comment period, that's why we have asked questions on the proposal, the Staff outreach. We asked specific questions; some of the answers led us down a different road and caused us to ask some questions. We've done our best efforts to develop something that balances both interests, so to speak, and this is a good step in the right direction.

COMMISSIONER BROWNELL: Great. Well I appreciate the fact that you were indeed able to turn this around quickly and that we can, as we discussed earlier with the market monitors, solve narrowly-focused questions sometimes more quickly than saving the world kinds of rulemakings. So thank for doing this. But this seems to be a pretty reasonable set of ideas and I look forward to the comments.

CHAIRMAN WOOD: I do too.

COMMISSIONER KELLIHER: I also support the proposed rule and I think the proposed rule properly recognizes that the current imbalance tariff provisions were designed to assure reliability by encouraging accurate scheduling, but the NOPR also recognizes that there are certain characteristics relating to intermittent generation where it makes it less -- well it certainly makes it more difficult for them to accurately schedule and the NOPR concludes that because of those different characteristics the current imbalance provisions are unjust and unreasonable, unduly discriminatory, and preferential, and I support those conclusions. Under the NOPR, the intermittent generators would not be subject to the $100 per megawatt hour penalty, but they do bear the costs of -- my understanding is they do bear the costs of imbalances that occur as a result of inaccurate scheduling. So in effect the $100 per megawatt hour penalty is waived but cost responsibility is not waived. So that gets to Nora's point about subsidies.

And I think we have tried to take a balanced approach here. We've tried to accommodate the distinct characteristics of intermittent generators without jeopardizing system reliability, and I hope we got the balance right and I guess comments will inform us on that point.

We've also solicited comments on the proposed definition. This is -- a lot of our discussion has been about wind, but this is an intermittent generator NOPR and there's a definition for intermittent resources and more than wind will likely fall under that definition. I'm curious how much will fall under that definition and I hope comments will advise us on that. First of all, how many different types of generation resources could be considered intermitttent, and then how much of the generation pie much fall under this NOPR? So those will be some interesting points. And this also -- this NOPR isn't the final rule, the final word of the Commission on imbalance penalties. We've talked a number of times about possible action on OATT reform and imbalance penalties are something that the transmission customers have raised outside the scope of intermittent generation. So we've raised a number of issues here this morning in the market monitoring presentation and the long-term transmission rights presentation of possible issues that will be considered during the course of OATT reform and this is another one. So I do support the proposed rule and look forward to voting.

COMMISSIONER KELLY: I wanted to -- I was going to make the same point you did, Joe, I think that's an important one, that we haven't changed the liability for the cost of balancing, we've just eliminated the penalty. But I also wanted to point out in response to Nora's concern -- or raising the issue whether there's subsidization, is that we do have a bandwidth. And we've tried to estimate in our proposal what amount of deviation is appropriately acceptable because of weather deviations, weather changes.

But we have a bandwidth, and generator overscheduling or underscheduling outside of that bandwith would still be subject to penalty. So we do recognize the possibility that there could be that kind of a behavior and that that kind of behavior should be penalized. And part of the comment process is to determine whether the bandwidth is the appropriate one.

COMMISSIONER BROWNELL: What's the comment period?

MR. DEAL: 30 days from --

MS. GADANI: -- from the date of issuance in the Federal Register.

CHAIRMAN WOOD: Let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is E-5. This is East Kentucky Power Cooperative, a presentation by Thomas Dautel, who is accompanied by Dan Hedberg, Cliff Franklin, and Jan MacPherson.

MR. DAUTEL: Good afternoon. On October 1st, 2004, East Kentucky Power Cooperative filed an application for a Commission order under Sections 210 and 212 of the Federal Power Act requiring Tennessee Valley Authority to interconnect its transmission system with East Kentucky. East Kentucky is seeking three new interconnections with TVA to allow it to provide full requirements service to Warren Rural Electric Cooperative Corporation following the termination of Warren's existing power contract with TVA on April 1st, 2008. The proposed order directs TVA to interconnect its transmission system with East Kentucky under Section 210 of the Federal Power Act and recognizes that such interconnection will facilitate Warren's access to cheaper power resources. Additionally, East Kentucky has requested that the Commission provide guidance on determining which system upgrades are necessary as a result of the interconnection.

Specifically, East Kentucky asks whether the base case analyzed in the system impact study should assume that Warren's load continues to exist on the TVA system as it does today. The proposed order finds that it should. In order to facilitate East Kentucky's service agreement with Warren, the proposed order encourages the parties to resolve their differences associated with interconnection arrangements and offers settlement judge procedures in support of that outcome. Consistent with Section 212(c) of the Federal Power Act, the Commission shall issue a proposed order and set a reasonable time for the parties to the proposed order to agree to terms and conditions under which such order is to be carried out. Accordingly, the parties are directed to submit to the Commission with 15 days after the expiration of a 30-day negotiation period all terms and conditions on which they have mutually agreed accompanied by explanations. If there are matters still in dispute, parties are directed to file on or before that date briefs to support their final positions.

And that concludes our presentation on E-5.

CHAIRMAN WOOD: Great. Any thoughts on that one? We don't do these very often, so I thought it was kind of worth focusing on on our 1992 amendments to the Act and we appreciate the opportunity to -- wish we didn't have to do this because I want everybody to work these things out. But we do have a tool that we can use and I think this is a good use of that tool.

Any comments? Joe?

COMMISSIONER KELLIHER: I do support the order. I think it meets the standards of the Act. I just wanted to make a couple of comments.

First of all, the Tennessee Valley is the one area of this country which, under current federal law, wholesale competition is prohibited, so it's unique in that respect. In this case, one of TVAs power customers would like to choose -- would like more than one choice of power supplier and they need an interconnection to do that. And I think the application meets the standards of 210, as Staff has noted and the order notes. The Commission concludes it would encourage conservation of energy and capital, it would optimize use of existing facilities and system resources, and we do provide reasonable time for the parties to work out the terms for carrying out the order.

TVA has raised an argument that Section 212(j) bars the Commission from issuing this order, and I think that's clearly incorrect. 212(j) is limited to wheeling orders issued under Section 211 of the Act, and this order is being issued under Section 210 of the Act. So I support the action.

I also would like to note that President Bush, in his budget proposal in February, did propose granting the Commission more jurisdiction over -- well, granting the Commission some jurisdiction over TVAs transmission system similar to what the Commission has over public utilities. And I think that's a good idea.

Congress has considered reforms to the TVA Act in the past and it was a very well written legislation, piece of legislation in 1999 that had a well-balanced TVA title that I would commend the Congress to dust off and look at. That 1999 bill, it would allow TVAs wholesale power customers more than one choice of power supplier, but it would allow TVA to sell excess power outside the region. So in effect it would operate a little bit like the preference provisions relating to Bonneville. TVAs customers would get first crack at TVAs power; if they wanted it, they'd have it first. TVA can only sell excess power outside the valley. And some TVA customers don't have an interest in choosing, some do. So this one does and we need an interconnect -- they need an interconnection order and they've met the standards of the Act. I do support the order.

CHAIRMAN WOOD: Anybody else?

(No response.)

Let's vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

Let freedom ring.

SECRETARY SALAS: Next for discussion is a joint presentation of C-1, Starks Gas Storage, C-4, Freeberg Gas Storage, and C-5, Caledonia Energy Partners. It's a presentation by Webster Gray, Frank Sparber, and Maria Farran.

MR. GRAY: Good afternoon, Mr. Chairman, Commissioners. My name is Webster Gray from the Office of Energy Projects. With me at the table for this part of the presentation is Frank Sparber and it appears we'll have to do without our legal representation at this time; Maria apparently can't make it.

I have a set of slides which, as you can see there, we're reporting on three new storage projects which are proposed in the Gulf Coast area. These are the Starks Gas Storage, Freeberg Gas Storage, and Calendonia Energy Partners projects. Also note on this map that you can see the location of existing, proposed, and planned LNG facilities in the same general area. These facilities may have a need of high-capacity high-deliverability storage facilities in the near future.

The preliminary determination in the Starks project also addresses two other issues. The draft preliminary determination would deny Starks request for authority to hold its own gas in storage and make bundled sales. The draft order also addresses the issue of how and to what extent Starks may contract for capacity on other open access pipelines. It further requires an annual report of Starks use of such acquired capacity and similar language on contracting is contained in the Freeberg and Caledonia draft orders.

On the next slide you see the first draft order you're considering is Item C-1, is the PD on non-environmental matters for the Starks project. Starks is a salt dome cavern, actually two of them, which will provide an additional 19 Bcf of storage capacity and 800 MMCF per day deliverability in southern Louisiana. Starks proposes firm and interruptible storage service at marked-based rates under a traditional marked-based rate test.

In the next slide you'll see the second draft order which you are considering as Item C-4, the Freeberg project. This draft final order allows Freeberg to acquire a currently non-jurisdictional storage facility in northwest Alabama and to expand those facilities to provide 6 Bcf of working gas capacity and 160 MMCF per day deliverability to the interstate market. Freeberg will offer firm and interruptible storage, as well as various interruptible hub services: parking, balancing, mowing, and imbalance trading.

The third project is a draft final order in Item C-5, which authorizes Caledonia to convert a depleted gas reservoir to storage. This facility will provide an additional 11.7 Bcf of high deliverability, about 330 MMCF per day storage in the region. Caledonia proposes firm and interruptible storage and lending services, also at market-based rates.

To summarize this, these three projects would add, after a final review of Starks and construction, a total of 36.7 Bcf of storage capacity with a rather remarkable 1290 MMCF per day deliverability to a supply area which is experiencing rapid expansion of LNG imports. The Staff review of this project has had the valued input from a very large group of team members and, as I put in my written comments, too many to mention but too important to ignore. And this is merely the lead group here; there were many more that had a part in it.

I'll answer any questions you may have and then Todd Rucamp will give the second portion of this presentation on the LNG infrastructure expansion.

CHAIRMAN WOOD: Webster, thanks for the presentation and, more importantly, for all the work behind it. We sure like see storage facilities added here, I think particularly to synchronize with what we're going to talk about next, which is where a lot of the LNG is going in. That's a real useful tool to have for any market but particularly for one that's going to be bringing in large slugs of gas in that manner. So I appreciate the developers coming forth and the issues you all have dealt with. I know we had some new issues on this one in particular.

COMMISSIONER KELLY: And I think that it's very significant to emphasize the development of these storage areas. Last fall, when you all prepared the storage report, you noted that the INGA Foundation report had indicated a need for 77 Bcf of new storage in the Gulf region by 2020, and these projects, these three projects when they are fully developed, will provide a total of approximately 37 Bcf of additional working gas capacity in the Gulf Coast region. So here we are six months later with proposals that look to meet half of the perceived need by 2020. So I'm very encouraged and I think the country should be encouraged that the industry -- and I think FERC's policies as well -- have facilitated the development of these storage areas.

COMMISSIONER BROWNELL: I will be concurring and writing separately on C-1 on Starks. I think that I'd like to explore, without undoing 636, because, God knows, your youth was spent on that.

(Laughter.)

COMMISSIONER BROWNELL: And I think it's had a lot of very positive impacts, but I think there are certain conditions under which we might consider a waiver, particularly if it has the effect of increasing capital deployment and efficiency.

And then on all three, I'll be writing some thoughts. We've included some informational requirements. I think that in a market that's changing this quickly, you might actually want to do a periodic market review of the underlying market fundamentals, not unlike the infamous triennial review on the electricity side, but we might want to think about that.

I'm thrilled that these projects are getting done. I think you're right, Sudeen, in identifying the growing need. We may want to just be looking at some things to consider in the new world.

COMMISSIONER KELLIHER: I'd like to make some comments on C-1, as well, one of the Orders Nora mentioned. I do support the Order, and I do support the denial of the waiver of the Order 636 unbundling requirements.

But I do have a lot of sympathy for the arguments that were put forward by the Applicant in favor of granting a waiver, particularly with respect to independent storage projects.

It's clear that we need more storage, and it's clear that if we increase storage capacity, we'll have some impact on price volatility. The Commission, though, does have an ongoing proceeding that's looking at changes to storage pricing policies, both market-based pricing and cost-based pricing.

And it may well be that in the course of that proceeding, we might want to consider waiving Order 636 requirements, but I think we need to continue our deliberations in the other proceeding, we need to make some decisions, and I think we will in the next 75 days, make some decisions on our pricing policies.

And may end up being that it would be -- it might make sense to waive 636 requirements, particularly with respect to independent storage projects, but not today.

(Laughter.)

COMMISSIONER KELLY: Well, I appreciate Joe and Nora's comments, but I also spent my youth on implementing competitive gas markets, including pipeline transportation at the state level, in particular. And I think one of the reasons that we've achieved such a workably-competitive gas market, is because of 636, and, in particular, the unbundling requirements.

I think that we should not change that lightly, if at all. I think that if we had done that in the electric industry, we might have seen competition come more quickly.

The unbundling requirements have lot of good, serve a lot of good ends, and one of them is that it totally eliminates any potential for conflicting goals, and I think that's a very important principle in this market.

It may said that from time to time, you give up efficiencies when you don't allow integration, and that may be true. On the other hand, allowing integration, allows for a dampening of competition in markets that have monopoly aspects.

I think what I want to emphasize is that it does not look like we need to provide incentives. Storage is being built and there are other applications pending before us for more storage areas. So, I, personally, am very, very reluctant to consider making any exceptions to the unbundling requirement.

CHAIRMAN WOOD: I think I'll just associate myself with that and call for a vote.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye. All right, thank you very much for your accommodation. I think the Applicants did want to know where we were.

All right, moving on?

SECRETARY SALAS: Next, we will also have a joint presentation of C-6, Cameron LNG and C-7, Corpus Christi LNG, and this presentation is by Todd Ruhkamp, Paul Friedman, and Vinod Shekar.

(Slides.)

MR. RUHKAMP: Good afternoon. My name is Todd Ruhkamp, and I'm from the Office of Energy Projects, and today we're reporting on the continuing progress of LNG terminals in the Gulf Coast region. With me today are Paul Friedman and Vinod Shekar.

Before we get started on Item C-6 today, we'd also like to talk about some of the highlights of LNG in the Gulf Coast region. Slide, please.

This busy map of the Gulf Coast region shows the 24 new amended or modified onshore or offshore LNG projects that the Commission and Coast Guard have been working on for the past several years. Slide, please.

Next shown is a breakout for these 24 projects: The two LNG terminals in operation, the five new terminals, plus one terminal expansion that have been approved and are now under construction or undergoing final design and procurement processes. I think some of you recently attended groundbreaking ceremonies at some of these projects.

Today, under consideration, are a new LNG terminal and a modification to a project previously approved. The Commission Staff and Mirant and Coast Guard are working on 12 more projects that are in various stages of the NEPA process.

We also have one additional new project and one expansion that are being considered by industry sponsors. Next slide.

Turning specifically to Item C-6 on today's Agenda, this is for Cameron LNG. It's an amendment to Cameron's previous approval. They now seek an approval to modify their LNG berths and maneuver in areas to potentially handle the next generation of larger LNG tankers.

Now we'll go on to Item C-7. Next slide. The Draft Order on Item C-7 grants Corpus Christi LNG Natural Gas, Section 3 authorization to site, construct, and operate a liquified natural gas terminal near Corpus Christi, Texas.

The Draft Order also issues a certificate under Section 7 of the Natural Gas Act, to the Chanier Corpus Christi Pipeline Company to construct and operate a send-out line to accommodate the regasified LNG. The Draft Order also authorizes the blanket certificates for the Chanier

Pipeline. Next slide.

Corpus Christi's LNG facilities will import, store, and vaporize approximately 2.6 billion cubic feet of LNG per day. Some of the key facilities to be constructed include a marine terminal, consisting primarily of a turning basin and two ship berths; storage facilities, including 360,000 cubic meter storage tanks, vaporization, and send-out facilities, as well as other infrastructure and support systems such as water and electrical services.

Capacity rights for the terminal have not been awarded at this time, however, Corpus Christi LNG is negotiating those rights for Chanier Resources, who was awarded the full capacity of the Chanier pipeline during the open season process. Next slide.

The Draft Order also authorizes the Chanier pipeline to construct and operate approximately 23 miles of 48-inch diameter pipeline from the tailgate of the LNG terminal. This take-away pipeline follows existing utility rights of way for approximately 91 percent of its length, and then it connects with up to eight intrastate and interstate pipelines and terminates near the town of Senton, Texas.

The Chanier pipeline is sized to transport an average of 2.6 billion cubic feet of natural gas per day, and the Chanier pipeline has entered into a firm transportation service agreement with Chanier Resources for the full capacity of the pipeline.

The Draft Order also finds that Chanier Pipeline's proposal is consistent with the Commission's policy statement for certification of new interstate pipelines. There were no significant landowner issues, and customers on the interconnecting pipeline should actually benefit from the project by having a new source of natural gas from which to choose.

It is interesting to note that no party protested nor filed adverse comments in response to either the pipeline or the LNG terminal application. An Environmental Impact Statement was issued and concluded that both the Corpus Christi LNG and the Chanier Pipeline projects are environmentally acceptable and that the projects are constructed and operated in accordance with the environmental mitigation measures as set forth in Appendix C of the Draft Order.

We also has many team members working on Items C-6 and C-7, and they're listed on the slide. There are many more throughout the environmental and LNG engineering staff, and we'd like to thank those, too. It truly was a team effort on all our efforts and certificates in OEP.

This concludes our presentation, and we're now available to answer any questions.

CHAIRMAN WOOD: Nice job, as always, on the presentation but, more importantly, the work behind it. I know it was a lot of work to do these very significant pieces of infrastructure that probably between them are a billion and a half dollars of investment down there. I did note with some interest your comment about the intervention level. It is a whole 'nuther country, as we like to say.

Again, it's an important thing and it's something I didn't ever think we'd be doing, walking into the job when Nora and I came in here. But, you know, we made a response as we just talked about in the last time because we had a pretty fair conclusion back in the original Cameron case, which was called Hackberry before they changed the name, that the business model was not consonant with our regulations and so we did make an adaption to that. And I think it has worked and we've got now one of each business model, a vertically integrated one with Cameron and an open access terminal with Chaniere and we'll just see how those play out.

But I appreciate again the hard work and the aggressive timetable that we pursue for all of these applicants.

COMMISSIONER BROWNELL: Can I just take this opportunity, relevant to none of these specific projects, to make an observation for those debating public policy changes in the electricity sector. Pipelines and gas infrastructure get built because jurisdiction is clear. Transmission lines do not.

CHAIRMAN WOOD: The queen has spoken.

COMMISSIONER BROWNELL: I couldn't resist.

COMMISSIONER KELLY: Pat and I were at the groundbreaking of the Chaniere-Sabine LNG plant and it was a privilege to go to your home town, Pat, and I enjoyed it and it is -- for those of you who haven't been there, you need to go. It's different country and it's beautiful country and part of the beauty in the beholder's -- in the eyes of those beholders is LNG plants. They embrace them. And I think the rest of the country is pretty darn lucky that they do.

CHAIRMAN WOOD: I'll be warm in the winter.

COMMISSIONER KELLY: Yes, you will. So will we, thanks to you. I vote "aye."

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye. That's a vote for both, correct? Good.

SECRETARY SALAS: The last item for discussion, H-6, Verdant Power is a presentation by Lon Crow, John Katz, and Thomas Dean.

MR. KATZ: Mr. Chairman, Commissioners.

This order responds to a petition filed by Verdant Power, LLC, for a request from the regulatory requirements of Part 1 of the Federal Power Act with respect to an experimental hydropower project that Verdant proposes to put in place in the East River off Roosevelt Island near New York City. I'm going to give a brief summary of the order and, after that, Lon Crow will give a brief discussion of this and other similar innovative technical projects -- or, excuse me, innovative technology projects to give an idea of what's out there and what we may be looking at in the future.

In the draft order, the Commission posits a three-part test pursuant to which it could determine that a project such as that proposed by Verdant is not required to be licensed under Part 1 of the Federal Power Act. First, the Commission states that the project in question must really be innovative, experimental technology. Second, the Commission states that the project in question must be undergoing testing for the purposes of developing a license application. The third prong of the test is that the project cannot either put power into or displace power from the interstate electric grid. The order concludes that Verdant's project, which is experimental and which Verdant proposes to put in place for an 18-month test period, indeed passes the first two prongs of the test and further concludes that if, indeed, Verdant does not put power into the grid or displace power from the grid, it will not be required to be licensed under Part 1 of the Federal Power Act.

Lon?

MR. CROW: Thanks, John. Good afternoon.

What I'd like to do today is provide the Commission with an overview of the Verdant hydropower proposal which is the subject of today's order. First of all, I'd like to give you a snapshot of the kinds of non-conventional hydropower facilities that are being investigated for installation along the coastal regions of the United States. These facilities would generate electricity by converting the kinetic energy of ocean currents, tidal flow, and wave action.

Next slide, please.

The five areas of the country where there has been expressed interest in developing these kinds of facilities, of course, you have New York City, the Verdant proposal. The City of San Francisco had expressed interest in capitalizing on some of the large tidal fluxes of the San Francisco Bay under the Golden Gate Bridge and in other constricted areas of the Bay. Off the coast of Washington State, there is a proposal to use wave action. And then finally there are two developers interested in developing the power-producing potential of the Gulf Stream in the straits of Florida.

The first slide is of one of these proposals. It's by Red Circle. The Commission has issued several preliminary permits to develop facilities such as that in the slide. Each of these facilities have a capacity of 1 megawatt and the proposal could include installation of 20 or more of these facilities. To give you some idea of the size of these facilities, the rotators -- the rotors are about -- I think you advanced one slide too many. There you go.

The rotors are about 40 to 60 feet in diameter. The supporting structure is about six feet in diameter and these structures can be as high as between 60 and 120 feet.

The next proposal is that that's being set forth by Florida Hydro. These are eight 3 megawatt facilities each. As indicated in the slide, these facilities could be installed at depths of up to 200 feet. Electrical generators are contained within that ring structure that would rotate in Gulf Stream currents. The Commission just recently issued a preliminary permit for these facilities. That ring structure is about 60 feet in diameter. The torpedo-shaped ballast chamber is about 45 feet long. And again they generate -- each of the facilities generate about 3 megawatts.

The next slide is the Macaw Bay Project. It's a wave action facility proposed off the coast of Washington State. The particular facility is a 250 kilowatt facility. The proposal includes installing an array of four of these with a combined capacity -- or to create a combined capacity of about 1 megawatt. Basically what happens is the buoy rides up and down on the waves and forces fluid across a hydroturbine. The particularly proponent has actually started the licensing process using the alternative licensing process. That facility, the buoy is about 10-15 feet in diameter and they can be put in water depths up to 150 feet.

The next slide -- that's a picture of the early prototype of Verdant's facility. It illustrates the kinds of facilities that they are going to be installing in the East River. The diameter of the rotor is about 15 feet and the axle -- the actual generating system -- it's about three feet in diameter.

The next slide would indicate where they're going to put these facilities. They're going to be putting them on the East River, the east channel of the East River along Roosevelt Island, which is the island in the middle of your picture there. They'd be away from us at that bridge, they'd be upstream about a quarter of a mile upstream in that large bridge you see crossing the east channel. If they built the entire facility, as they currently propose it, that field of turbines would extend about a mile, which would be about half the length of that island. Next slide.

Verdant's specific proposal is to install six 21 kilowatt units. During an 18-month study period they would undertake tests to examine the technical feasibility of the project as well as monitor the environmental effects of operation of these units. Data that would be collected during these tests would be used in the development of a license application. The license proposal would, as currently planned, include the installation of several hundred units with a total built-up capacity of between 5 and 10 megawatts.

That concludes the presentation. Are there any questions?

CHAIRMAN WOOD: I appreciate the legal creativity here. It's one I clearly think makes some sense, particularly as we try and encourage new technology to come into not just the other two industries we regulate, but into the original industry we regulate, which is the hydro, this project and the others like it. Thanks for doing a survey, Lon, of the other ones in the country because I think, from being at the NHA meeting last week, there are a lot of real latent potential there for small projects like this. In the aggregate, they can make a lot of difference. But I think, you know, whatever role, kind of a blessing or at least an acknowledgment from the regulator can matter, I think I want today to be that. I think we can really weigh in behind innovation and technology and help push the envelope and bring the benefits -- jobs, technology, entrepreneurship -- to the coastal regions, which is a good place.

COMMISSIONER KELLY: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

The meeting is adjourned.

(Whereupon, at 1:55 p.m., the Commission meeting was adjourned, to reconvene in closed session at 3:10 p.m., this same day.)