BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MISCELLANEOUS ITEMS :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

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858TH COMMISSION MEETING

OPEN MEETING

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

Wednesday, May 5, 2004
11:15 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

ALSO PRESENT:

DAVID L. HOFFMAN, Reporter

P R O C E E D I N G S

(11:15 a.m.)

COMMISSIONER BROWNELL (Presiding): Good morning. Bill Massey had a whole day. I get about ten minutes, but I'm going to make the most of it. We're thinking company cars. I was thinking maybe plastic survery coverage.

(Laughter.)

COMMISSIONER BROWNELL: The troops want raises, so -- I don't know. We're for 'em. What do you think?

COMMISSIONER KELLY: I'm with you.

(Laughter.)

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

Let's begin with the Pledge to the Flag.

(Pledge of Allegiance recited.)

COMMISSIONER BROWNELL: For those of you who may be speculating that the FERC running team was so challenging that we lost Pat along the trail, he is testifying before Congress, but I congratulate the team, and particularly our outstanding performer who got a medal.

(Laughter and applause.)

COMMISSIONER BROWNELL: This is a formidable group in every regard. This morning, we're going to open with presentations by the Market Monitors, if they would come up to the table, please.

We're going to begin with Bob Ethier. Welcome, Bob, David, and Anjali. Staff is free to ask questions. I think these are important reports and we learn a lot from this.

SECRETARY SALAS: Let me just say for the record that this is Number A-3 on the agenda, Market Monitors, State-of-the-Market Presentations.

MR. ETHIER: Good morning. Thanks for the opportunity to come and talk about the New England markets and how they've functioned over the last year.

(Slide.)

MR. ETHIER: A lot has changed in New England in the last year. The biggest news is clearly that on March 1st of last year, we implemented standard market designs, so, LMPs, day-ahead, and real-time markets, virtual trading, and a whole host of software changes and improvements replaced single-energy price markets and our real-time-only market.

That was a very big shift for us, and certainly the summary there is that we've been very happy with the transition. We felt it went well.

We feel the markets are working well, both at sort of a theoretical level in terms of incentives, but also working well at sort of the detailed sort of software level. Generally, we think that's a very positive story.

There are incremental improvements we're seeking to make to the market, that we sort of expected before we implemented it. It's probably not a complete set of markets yet, but we feel that what we implemented is working well and we're happy with that.

What I will largely be talking about today is sort of the results of that market. The one sort of caution I would put out is that the data is a little confusing because we radically changed our market design, sort of in midyear.

And this is a year-long report. There are going to be some instances where we're sort of melding pre-SMD data and post-SMD data. I tried to note that on the slides and so forth, and we've made some simplifying assumptions to allow us to do that, but I think the numbers are still representative of the true results.

The other thing, I guess, just to sort of tee-up the presentation, I did review what was presented at the last meeting by the market monitors, and you can see a lot of commonalities between what I present and what New York, for example, presented, both in terms of the metrics -- clearly, we all agree on at least five standard metrics, but also the results for New York are quite similar to those that you would have seen in the New York ISO.

The markets behaved competitively, but prices did go up quite a lot over the last year, primarily because of fuel price increases. Gas price increases were dramatic from 2002 to 200 3, and we have some numbers that attempt to adjust energy power prices for the change in fuel prices.

It shows the large effect gas price increases have had in the New England markets over the last year, so that comes later on. Is the slide show going to come up on the screen?

(Slide.)

MR. ETHIER: As I mentioned, gas prices went up dramatically, about 74 percent between 2002 and 2003. Electricity prices actually peaked in February and March, which is unusual. Typically, we would see peaks in the summertime during the high demand periods.

(Slide.)

MR. ETHIER: But we had two things going on: We had a dramatic peak in gas prices in February and March, which, unfortunately, coincided with our SMD implementation, which caused some consternation. So we tried to sort of explain what was going on, and summer loads were relatively low. We had a relatively cool summer in 2003.

We didn't get to the dramatic load levels and price levels we had seen in past years.

(Slide.)

MR. ETHIER: If you look at the slide that is entitled New England Electricity and Natural Gas Prices, which I believe is the next figure --

(Slide.)

MR. ETHIER: -- you can see the high energy prices in February and March, and they coincide with the high gas prices during that time period. The average gas prices were over $10 an MmBtu, which is really a dramatic run-up, and was a huge influence.

What's not on this slide, but sort of connects those two lines, is the fact that gas is between 30 and 50 percent of the installed capability in New England, which is a relatively high number. But even more importantly, gas is the marginal fuel in New England, well over 60 percent of the time, so gas-fired units are setting LMPs in either all of New England, or a significant subset of New England.

In excess of 60 percent of all pricing iterations in the day-ahead and real-time markets -- that number gives you a sense, I think, of how sensitive we are to changes in the gas price in New England, and they really flow pretty directly through to energy prices.

(Slide.)

MR. ETHIER: This next slide that you'll see is the energy price duration curve. That's going to be consistent with what we just talked about.

(Slide.)

MR. ETHIER: If you look at the blue line, which is the 2003 line, that's almost everywhere above the preceding two years. That just shows that in the vast majority of hours, energy prices, on average, were above what they were the preceding two years, largely because of gas price changes.

It doesn't come across too clearly in this figure, but on the left side, which is the highest priced hours, that's where things sort of reverse relative to previous years, and, again, that's the cool Summer that you see there. We just didn't have a lot of relatively high-load days.

Some of the numbers are probably more helpful than this small graph. Real-time prices in 2003 exceeded $500 for only one hour.

(Slide.)

MR. ETHIER: This is a relatively low number of ours. They exceeded $500 for four hours in 2002 and for 15 hours in 2001, so, really, we just didn't have the peak days last Summer that we had in previous years. It was mild weather that played a role there, but probably the other thing that played a significant role there is, we've had significant new generation additions in New England.

In the last two years, we've had about 6,000 new megawatts come online in New England. The vast majority of that is efficient, normally inexpensive, combined-cycle, gas-fired capability.

That certainly had a significant influence on the summertime prices that we've seen.

(Slide.)

MR. ETHIER: If you move to the next slide, which is the load duration curve, it's a little easier to see that the Summer effects, versus the sort of annual effects -- again, you see the blue 2003 line is nearly everywhere above the previous load level, the load levels for previous years.

So, on average, we did have more demand, sort of the typical hour had more demand that previous years, but when you get to the left-most portion of the graph, the blue line starts to go underneath the previous years, which really is the Summer months sort of revealing themselves in relatively low load levels.

So, all these messages are really consistent with one another. Now, for some of the maybe less intuitive or sort of more calculation-based metrics:

(Slide.)

MR. ETHIER: The next one is the all-in energy price. What we do with the all-in energy price is, we say, okay, let's look at all the costs, the market costs that the ISO calculates, and let's levelize them over all the megawatt hours consumed over the year to come up with basically the total cost of consuming an average megawatt in New England in 2003.

What that allows us to do is put capacity prices, facility service prices, uplift costs, all in sort of one metric, so you can sort of see how they influence the average cost of consumption.

Probably the biggest message there is that energy is by far the biggest component of the average cost of serving electricity needs and running the system in New England. What you'll also see on this slide is that we have two different bars for each year. We have sort of the actual energy prices, capacity uplift, and so forth, but we've also done a fuel-adjusted version of that.

So, what we've tried to do is strip out any change due solely to fuel prices and normalize it so that all the years are on an equal fuel price footing.

You have to caveat it slightly. There's no really perfect way to do that, but the numbers show the impact that fuel prices have had.

(Slide.)

MR. ETHIER: If you go to the figure, you'll see that for each year, 2001, 2002, and 2003, there are two columns. The first column is the nominal prices, the actual prices participants paid, and then the green bar is the fuel-adjusted energy component with the other categories held the same.

You can see that when you adjust for fuel prices, there's a pretty dramatic change in the way the years look, relative to one another. FYI, the year it was normalized to was the year 2000, so they are all on an equal footing.

You can see that once you adjust for fuel prices, it seems that power prices have actually fallen over the last three years. I would say that's due to the two factors we've already talked about, which is the new unit additions, the new cheap combined cycles coming in, efficient combined cycles coming in, and especially in 2003, the relatively mild Summer we had, that basically didn't cause us to have any $1,000 hours or any high-priced hours.

Again, I think the message there is consistent, and to me, it's important to strip out that fuel price change to the extent that we're able to, because it provides maybe a more fair picture of how the markets themselves operated, exclusive of these external influences that we can't really control.

MR. HEDERMAN: Bob, just a quick clarifying question: The way you've made that adjustment is no redispatch calculated, so it's simply the units that were dispatch, and adjusting for their fuel use?

MR. ETHIER: That's correct. It's an imperfect way to do it, but it tries to strike a balance between sort of computational reality --

MR. HEDERMAN: It makes sense. I just wanted to clarify it.

MR. ETHIER: The other thing that I would point out here is, of the little bars at the top, if you will, there are three categories: There's uplift, which has had a variety of names in New England over the last three years, so I just used the catch-all category of uplift capacity and ancillary services.

Uplift and ancillary services haven't changed dramatically. The largest change of those three bars is really the capacity price, which has steadily fallen in New England over the last three years, which, again, because we run a pool-wide capacity market, in my view, it's consistent with the capacity situation we've had in New England.

We have relatively robust reserve margins right now, and you expect the capacity price to fall in reaction or in response to this relative large amount of capacity relative to demand.

(Slide.)

MR. ETHIER: Then there is the final sort of metric that we have of the five official metrics, is economic incentives for new investment.

(Slide.)

MR. ETHIER: If you'll just sort of slide further along to the actual table, I'll get right to the punchline here. What we've done is, we've calculated -- estimated, actually -- what sort of a hypothetical combined-cycle and a hypothetical combustion turbine would have earned in the New England markets in 2003.

This is a standardized metric amongst all the ISOs, so we've used similar assumptions for these hypothetical units, 7,000 heat rate for the combined-cycle, 10,500 for the combustion turbine running on gas.

We basically dispatch against the realized electricity prices through the year, with the appropriate gas input prices, and calculate a net revenue. The second line from the bottom of the table, the underlying numbers, under the combustion turbine and the combined-cycle, give you the net revenue that one of these hypothetical units would have had to apply to its fixed costs, and, for the combustion turbine, it's around almost $13,000 a megawatt year. For the combined-cycle unit, it's about $77,000 a megawatt year.

What you see immediately below that are the ISOs' estimate of what the carrying cost of one of those units would be. You can see that there's a pretty dramatic difference between what these units would have earned, if they actually ran as we projected, versus their estimated carry costs in the market.

Neither of the units would have come particularly close to covering their costs. They would have been, well, sort of under water, if you will, for that particular year.

The combined cycle is relatively good compared to the combustion turbine, and I would chalk that up basically to the mild Summer. A lot of the combustion turbines just didn't even get called during the summertime, because we just didn't have those peak load days.

That trend needs to be looked at in the context of our overall market. The question I ask is, is that consistent with the market structure that I see right now? I guess it is.

But as we have a pool-wide capacity market and that capacity market is long, because we have a relatively large amount of capacity and you would expect capacity prices to be relatively low and energy prices to be relatively low.

So, this one snapshot is consistent. Clearly, if this persists for years and years, then we have a problem, especially if the underlying generation capability versus load, starts to change and this number doesn't. That's when it would become a concern.

(Slide.)

MR. ETHIER: The next figure is a forced outage number.

(Slide.)

MR. ETHIER: Real quickly, I would note that we don't have sufficient (e)(4)(d) data, which is the standard way that we're going to be presenting this in the future. So we've used general percent of units unavailable on weekdays.

The one thing I'll highlight on this figure would be basically the downward trend that we see in the percentage of capacity unavailable on a typical weekday. It's encouraging to me.

One would hope this trend would continue, because what our research has shown is that the new units that come on the system typically go through some sort of break-in period, some break-in pains, where their unavailability seems to be higher than it is ultimately after five or eight years, once they've really sort of sorted things out.

Because we have so much new entry during this time period, those sort of birthing pains, if you will, have been reflected in these numbers. I would hope that these numbers continue the downward trend, once those things get sorted out.

(Slide.)

MR. ETHIER: I think the final figure that we probably ought to talk about is the competitive benchmark results. This is not a standard metric because it's a relatively complicated modeling effort that at this point, all the ISOs do somewhat differently.

It really is an attempt to sort of do the intuitive thing, which is okay if the market operated perfectly competitively, or our best estimate of that, how does that compare to what we really saw in the marketplace? We've calculated these numbers for 2002 and 2003.

(Slide.)

MR. ETHIER: What I would have you focus on is those numbers on the right-hand column, the percentages. That shows the percentage above this sort of perfect-world number, if you will, that the actual ECPs and the actual bids were, I would say that the single-digit percentage numbers are what you really want to be aware of.

Basically, these numbers are consistent with the story that the markets were competitive. The markups that we estimate are small and probably within the range of error of the modeling effort. I would start to be concerned if these single-digit numbers sort of increased to 50 percent, for example.

That would say, okay, there's something going on in our markets that either we're not modeling well, or there's an inefficiency or there's a lack of competition. But what these numbers say to me is that within the error bands of the model, the market is working reasonably well.

That's been a consistent message for the last couple of years.

COMMISSIONER KELLY: Bob, would you mind taking a few minutes and walking us through this table here in a little more detail?

MR. ETHIER: I'd be happy to do that. What we've done is sort of brought inhouse, a modeling effort that's been largely spearheaded at the University of California, Berkeley. The idea is that in the electricity industry, you have a relatively good sense of the costs of production.

You can actually go out and estimate what it ought to cost to serve load in a certain hour, given all the heat rates of the units, fuel costs, assumptions about VOM costs, and so forth.

What we've done is built a model that does that on an hour-by-hour basis. What we do is compare it against two different things: We compare it against the actual prices that you see in the marketplace, and also compare it against our bid stack, which is something that ISO is able to do in a way that a university is not, because we have access to all the confidential data.

I think that's a real sort of value we can add.

COMMISSIONER KELLY: When you say you compare it to the bid stack, what do you mean? Do you look at all the bids in there, or a bid that's taken?

MR. ETHIER: That's exactly what we do. We compare it against all the bids in there. The reason we do the two comparisons rather than just one, is because what we do is a model. It necessarily ignores some complexities of unit commitment costs, startup, and load costs, transmission constraints. It strips those things out, and by comparing our model amount to the bid stack run through the same model, you get more of an apples-to-apples comparison.

MR. ETHIER: We take all the bids that are submitted each hour, run them through the exact same model that we run our estimated cost through and get a fair comparison, if you will, of the actual bids that were submitted and the prices that would result if they could be dispatched perfectly each hour with our estimate of the market would look like if you dispatched it perfectly each hour.

On one level it makes things a little more confusing, but on another it allows us to stripe out the things that we know the model doesn't capture well and make it a little cleaner. That's actually the number that in the top figure is negative which shows that on average in 2003, according to our modeling effort, our estimated cost are slightly above the actual bids that came into our market when we dispatched them through the same model. That's where, I think, a caveat about it's a model comes in. I wouldn't read too much into this negative number. I think I would read it more as the model has a certain error band as all models do and the error band in this model is probably at least 10 percent, plus or minus. So I don't get too worked up about these fine gradations. It's much more useful, I think, to look at it over time. And, if you see large changes over time with a consistent model, that's when you would start to sort of wonder what had changed in your market.

(Slide)

The next slide I would sort of go to, I guess, is sort of the other conclusions, which are sort of the things I didn't want to take the time to present in gory detail, but that I think are worth at least highlighting. We had good convergence between our day-ahead and real-time markets. The prices vary by a little less than a dollar, which, frankly, was probably less than my estimate going into it because I thought that there would be some sort of break in the issues where people were sorting it out. But I guess I would attribute it to the fact that we've got a lot of relatively sophisticated participants who have participated in PJM, who have participated in NYISO and brought that experience to New England. So they knew how to deal with the markets, knew how to sort of operate with price-sensitive demand bids and things like that. And they helped our markets converge relatively quickly. That's generally a good thing.

Virtual trading volumes were, in my estimation, reasonable. It's going to take a little time to fairly evaluate how robust those volumes are, but given that it was brand new, we had people stepping in right away and engaging in virtual trading and providing liquidity to that day-ahead market, which we value.

(Slide.)

The next slide. The one thing I would echo, the New York report from last time was that the real-time prices in the region do continue to be inefficiently arbitrated. There are price differences between New York and New England that occur when the tie lines are not fully utilized that continue to persist. That's undesirable because there's some profitable trades that are happening and there are some efficient generation in one of the markets that's not being dispatched at the expense of less efficient generation in the other market.

The demand response program has improved in 2003. We're up to about 335 megawatts signed up. Frankly, we need to go further in that direction and we need to get more megawatts signed up for that program. And, even more importantly, we need to get a greater portion of megawatts responding in that program during price events. The response of that 335, on average, was about 18 percent. So our typical demand response during an event was in the range of 70 to 80 megawatts, which is pretty low in a pool where the peak demand is 25,000 megawatts.

Regulation was our only ancillary service in 2003. We did identify a market flaw there in late 2003 and we corrected in early 2004, which I think is a useful case study that we went over with staff yesterday.

(Slide.)

And I guess the two sort of big issues that I see facing us in 2004 are market design issues. One that is sort of merit operation, especially in constrained areas, continues to be a problem. Part of that is just a lack of appropriate infrastructure in New England, quick start resources primarily. Hopefully, our new forward markets will provide the right incentives there. The other is an ongoing issue not unique to New England, which is the resource adequacy issue.

That concludes my formal presentation. I'll be happy to take any additional questions. If I've sort of steam rollered over anyone that's trying to get a word in.

COMMISSIONER BROWNELL: We're use to that.

(Laughter.)

COMMISSIONER BROWNELL: I have a couple of questions. It seems when you look at page 17 that the Boston area kind of anticipated LMPs and either built something or entered into long-term contracts. You don't say that, but is that actually what happened whereas Connecticut did not?

MR. ETHIER: I think that's a very good point. In some ways, I guess view it as SMD sort of had some success even before it became implemented. People were very much expecting high LMPs in the Boston area because, historically, it's been a constrained area. But what we saw, even prior to the implementation of SMD, was significant transmission upgrades in the area and we also saw significant generation investment. We had 14 or 1600 megawatts of brand new combined cycle plunked in Boston, which is huge. That's a large investment and that's a lot of progress and the transmission investments -- incidently, weren't the sort of big-bang investments that lots of people looked for. There are lots of incremental investments which, frankly, are laudable and probably are underappreciated by folks.

They significantly increase the transfer capability and both of those, at least in my view, were, at least, partly prompted by the expectation of congestion of high prices in Boston and they worked. They really combined with the relatively low load summer. They really did smooth out any congestion that was likely to have happened in Boston and reduced the congestion component we saw in that area.

COMMISSIONER BROWNELL: So your advice to your colleagues here who are anticipating an LMP market with market participants who are, frankly, skeptical would be the nicest way I could put it, would be that anticipating and developing an appropriate response is helpful and can be managed. That LMP does not, in fact, inflict unnecessary pain unless you chose to let it.

MR. ETHIER: I would agree with that. And we just talked about two specific examples of investments, but I think there are a whole host of, in my view, positive and efficiency-enhancing reactions throughout New England to the coming LMP. Frankly, things that have been on the shelf for a while that got pulled off the shelf and implemented because there was an economic incentive to do so. I think there are a lot of actions that can be taken. They are not just $5 million worth of transmission lines. There are lots of incremental investments that can make a big difference.

COMMISSIONER BROWNELL: Bob, you talked about market participants who'd had experience in other markets, including PJM. So that's the issue of training and sophistication and the ability to manage through those changes was enhanced by that. Do you have any advice to your colleagues in terms of training and anticipating, since their market participants have largely not participated in those markets?

MR. ETHIER: I'd guess there would be two areas I would suggest. One would be to basically encourage these market participants to go to PJM or go to NYISO or go wherever it is and see how the markets work, talk to the participants, be part of the stakeholder process, even as an observer, the other one maybe because I'm at the ISO and I see this every day. But we had a pretty extensive, probably expensive, too, training and market trial period. Our market trials -- we had three sets of market trials. Each roughly a week long in which all participants were eligible and very much encouraged to participate in. That serves two useful functions. It gets the participants sort of nailed down so they can figure out what's going on, but also helps the ISO vet it assistance. I think that was hugely important, both in getting people to understand how the markets would work, but also to iron out any potential glitches on both the participant's side and our side. I think you can't do too much education of participants prior to the fact.

COMMISSIONER BROWNELL: There must be a planning processing place that's been reasonably efficient as well, if, in fact, people actually got things built in anticipation of a marketplace.

MR. ETHIER: I think that's true. We've had an RTEP process, which is a regional transmission expansion plan report for a number of years now. One of the important parts of that report is to highlight areas that sort of concern on the transmission system and sort of provide information to investors, basically, of here's where you might make some profitable investments and really help the system out at the same time.

COMMISSIONER BROWNELL: Just one more question and I'll open it up. One page 23, you talk about the arbitrage. What is the problem and what is the solution?

MR. ETHIER: I guess I would chalk it up to sort of two problems. One is this sort transaction fees that currently go with exporting or importing into a controlled area. That's going to build in, inherently, a margin between two controlled areas. That doesn't help efficiency at all.

The other issue is just the timeframe in which folks are able to submit these transactions almost inherently prohibits people from efficiently using the interface. They have to be given far enough in advance. And I want to say it's about 60 minutes in advance that they can't react to the latest information and fully utilize that interface. Prices change dramatically. Utilization changes pretty dramatically on very small increments. But the way the transactions are submitted doesn't coincide with those equally small increments.

That's something I know New England and NYISO are working on. And my understanding, and I should be careful about projecting this, but that NYISO is implementing a software enhancement in the next six to eight months that's going to help a lot in that regard in terms of increasing the flexibility of those transactions.

COMMISSIONER BROWNELL: Thank you.

Joe?

COMMISSIONER KELLIHER: I have a question about the market flaw that you identified on page 23, the ancillary services market. Could you tell me how was the flaw identified? Was it identified by the market monitor analyzing outcomes or by a party that thought the rule was operating to their detriment and how was a correction developed? Was it developed by the market monitor? Did you propose a rule change? Did we act on the rule change? I just wanted to get an appreciation of how flaws and rules are identified and corrected.

MR. ETHIER: I would say in this case it was sort of identified in parallel. We had some market participants, specifically, some generators, who started asking some questions about the regulation market. They sort of felt that they should have been basically cleared in the market because their offers were competitive and they were not and they couldn't figure out why that was. And sort of simultaneously with that we were looking at a price rise in the regulation market and we started to sort of dig a little deeper into the rules underlying the regulation market and we found that, basically, without going into too much detail, when we looked at the rules there was a real flaw that you could see that sort of set -- in the regulation market which didn't incite people to operate and provide their sort of most competitive bids in the regulation market, basically, where we sort of brought that to light.

COMMISSIONER KELLIHER: How did you identify that there was a flaw? Was it by looking at pricing or looking at bidding behavior?

MR. ETHIER: What first tipped us off was the prices. When we saw the run-up in prices. It wasn't 100 percent. It was more on the order of 30 percent or something like that, but that caused us to look at the market. Then we said, okay, let's take a closer look at these rules. We looked at the detailed rules and talked with the systems operators about how the implemented those rules.

In the course of that investigation, it became apparent that there was a strategy that basically undermines the incentives provided by the market. So it's probably more it was the data that tipped us off to look harder. Then, once we started looking harder, it became evident that the rule wasn't efficiently designed. Does that sort get to your question?

COMMISSIONER KELLIHER: That gets to the question how it was identified. How did you develop a correction?

MR. ETHIER: The correction really began, I guess, at the ISO. We said we've identified this flaw in the design. Here is the most sort of -- the best way to fix it, given the constraints that you want to avoid redesigning the whole market if you can because that's a much more costly, time-consuming process. We tried to identify a relatively speedy fix that would also be efficient and were able to do that. It was actually quite simple. It didn't require a software change. It just required a procedural change and a change to a detail in the market rules.

We walked that through the stakeholder process. We went out and said, look, here's the problem we found. Here's our proposed solution to this problem. What's your reaction, provide us input? Inevitably, that's a useful process to go through because the participants had a lot of comments and they help you improve your implementation of the rule. It was actually during that process that some of the disadvantaged participants said, you know, we appreciate you coming forward and doing this because we've been seeing this and we weren't sure what was going on and this is the kind of thing we want you to do. In my view, it sort of ratified the research that we had done and the conclusion that we had come to.

COMMISSIONER KELLIHER: How long did it take from the point when you identified the flaw -- one more question, was this correction something you could do unilaterally or was it something the Commission had to approve?

MR. ETHIER: I believe it was something we were able to do unilaterally. One second. It was stakeholder approved because it was a manual change and it wasn't explicitly in the market rule. It was a manual change, so it really had to do with a deadline for markets. That was in the part of the rules, basically, that are stakeholder approved. So we had to walk through the stakeholder process, get their vote and the vote was pretty much overwhelming to change it, to eliminate it, this flaw. That took about two and a half months to go through the stakeholder process and actually implement the rule change.

COMMISSIONER KELLIHER: You said it was in the guideline or a guide.

MR. ETHIER: It was in our manual. We have market rules that come here and are approved. And then there are some details to those that are approved at the stakeholder level and can be changed at the stakeholder level and this is one of those details.

COMMISSIONER KELLIHER: How do you enforce those rules? How are the rules enforced that aren't subject to the Commission's approval?

MR. ETHIER: I guess I would say that they are enforced in the same way. Sometimes they fall under my sort of purview. Sometimes they just are more general ISO rules that -- you know, in this case, what it is -- let's use this as an example. We changed the deadline by which you had to offer something. So we just refused to accept things that came in after the revised deadline and that was the enforcement mechanism. So it was entirely within the ISO's control to enforce that change that had been approved by the stakeholders.

COMMISSIONER KELLIHER: How long did it take from start to finish?

MR. ETHIER: Two and a half to three months from the first time we went to the stakeholders. We went to a relatively low-level participants committee meeting twice to explain it and to explain the proposed solution. Then we went to the broader stakeholder group where we actually got the official vote to change it and then it was implemented, basically, coincide with that approval.

COMMISSIONER KELLIHER: One last question, how often are there rule changes in a year and to what extent are they made unilaterally and to what extent are they submitted to the Commission for its approval?

MR. ETHIER: I would say the majority of them come down here. I wouldn't even hazard to guess as to how many rules we change a year, especially, now that we've gone live with this new market. We're sort of discovering all these nuances, if you will, that need to be revised.

COMMISSIONER KELLIHER: Is it scores or hundreds?

MR. ETHIER: Scores, I would say. And, oftentimes, when you change a rule, it changes the rule in a number of different places.

COMMISSIONER KELLIHER: Again, rough order of magnitude, how often are rule changes identified by a participant who complains and believes the rules are acting to their detriment and how often are they identified through your analysis?

MR. ETHIER: I would say that a lot of them, frankly, we rely -- I don't know if we rely on the participants, but they uncover them first because they're looking at their detailed data. They know how their plant was operating and they say, look, something weird happen and then we look at it and, oftentimes, we go, you're right. That's certainly now what we would have intended when we wrote this rule or when we wrote the software or whatever the issue is. I would say the participant feedback process is critical to it. Maybe that's probably more than half the rules that come up. They might be initiated by a participant sort of raising their hand and then it sort of gets dumped over to the ISO to sort of ferret it out, propose the change and carry it through the stakeholder process.

COMMISSIONER KELLIHER: Is there some way you can provide us a letter to get exact numbers on how many rule changes a year and how many are made subject to the Commission's approval and how many are made unilaterally?

MR. ETHIER: Sure. I think we can do that. The thing, just to be clear about, you know, the change to the regulation market was in an area that, at least, historically, has been a stakeholder -- the manuals are at the stakeholder level and they typically don't come down here.

MR. ETHIER: The rule changes and market rule one have to come down here. There's no discretion about whether we provide it to you or not.

COMMISSIONER KELLIHER: One quick short one, the virtual trading, you said the level of activity was reasonable. Can I infer disappointment from the use of reasonable?

MR. ETHIER: I think you infer more lack of a firm expectation of what it ought to be. It seemed like there are a fairly high number of players engaged in virtual trading. We're clearing hundreds of megawatts every hour, but I don't know if there's a right number there. It varies dramatically, which is what you would expect. So I guess I'm comfortable with it. It's not so small that it's worrisome or it's not half the market in the day-ahead, which might worry me as well because then you'd wonder where all the physical resources were going. So I think it reflects more that there's not really a right or wrong. There are just extremes that you might be concerned about.

COMMISSIONER KELLIHER: Is it a lower level than in New York?

MR. ETHIER: I thin it's higher than New York. David could probably address that more readily than I could.

COMMISSIONER KELLIHER: Thank you very much.

COMMISSIONER KELLY: I wanted to ask you a little bit about congestion costs. Do you know how much of the congestion is hedged in New England through FTRs?

MR. ETHIER: That is a tough question. Certainly, all the congestion, basically, could be hedged in New England because we auction off the FTRs and they're all available. David has done some work in New England and the work we've done in New England as well supports the idea that, especially, in the first months of the market it wasn't nearly fully hedged as you would like. But it seems that level is steadily increasing to an extent I'm comfortable with that because there's a lot of learning that has to go on in this market. People have to understand where congestion is going to arise and how to value it.

What I would hope is that especially this coming summer that we see the FTR market more fully subscribed, if you will, than we did the first summer because people have a heck of a lot more data with which to make their informed decisions about buying FTRs.

One of the issues with FTRs is that they are risky. They can turn around on you and you can actually owe money on what you paid money for, which is never a pleasant experience. So I think folks wanted to see some real market data before they really jumped in and took what potentially could be a risky move on their part.

COMMISSIONER KELLY: When you started out with the FTRs, did you allocate them or did you auction them?

MR. ETHIER: Well, we basically only auctioned FTRs. What we do allocate are the auction revenue rights from the FTR auction. So at a very high intuitive level, all of the revenue from auctioning off the FTRs goes to the load in the constrained areas, sort of abstracting, to a large degree. But that's basically what happens. So what we tell people is, you can go in and buy the FTRs if you value them most highly. But, if you don't, we're going to sell them to the people who value them the most. What you're going to get out of it, load in other constrained area, is you're going to get the money from that auction paid to you to offset those congestion costs. To date, that seems to work pretty well and I think we're pretty happy with the method we've adopted.

COMMISSIONER KELLY: In Connecticut, of course, there's significant congestion. Are you seeing the price signals of that congestion being passed on to the consumers or is it being effectively hedged in such a way that they don't see the cost?

MR. ETHIER: I would characterize it -- it's being passed on in the sense that the standard offer prices in Connecticut are higher than they would be without the congestion. So they're getting it on sort a levelized, seasonal basis. The out-of-merit costs in Connecticut are also directly assigned. The consumers are seeing that and the state regulators are acutely aware of the impacts of congestion on their standard offer prices. They are not seeing the hour-to-hour congestion events feeding through to their prices. They're only seeing it through this longer run pricing mechanism.

COMMISSIONER KELLY: Do you think that the way they're seeing the price is appropriate? That is sufficient to induce necessary changes in behavior or efficient changes in behavior? Do you think we need to refine that?

MR. ETHIER: I think we do need to refine it. More directly, under the ISO's control is the whole issue of out-of-merit operation where we turn units on for reserves and they're not reflected in the clearing price. That's something we're continuing to work on. That's the most critical aspect of what we can do to send better price signals in terms of would it be helpful if hourly pricing were passed on at the consumption level. I certainly am supportive of that. There are a lot of regulatory and technical and cost barriers to doing that. But, certainly, at the industrial level, to the extent that there are industries in Connecticut, or the large commercial level, having that happen more quickly rather less quickly would be, in my view, be helpful. Really, that's sort of the ultimate in the demand response. You don't want -- in a perfect world, you wouldn't have the separate demand response program. You'd just tell everybody what the price is every hour and they could make their own decisions. We're, unfortunately, a long ways from that.

COMMISSIONER KELLY: Can you tell me about the forward reserve market?

MR. ETHIER: That's sort of a new thing in New England, a new thing everywhere. Basically, we have for a long time been concerned that we don't have sufficient quick-start capability. We've recognized that part of the reason is we haven't provided adequate incentives for folks to build quick-start capability. We don't reward it, basically, with a market price and market revenues.

In December, we had our first forward reserve market. And what we do in that market is we run an auction for a six-month -- normally, it would be a six-month strip. It might have been slightly shorter because of the implementation time of reserve provision, whereby you commit to providing reserves all on peak hours or, essentially, all on peak hours for the next six months. From the unit that you sold in that market, we, in turn, will give you a payment for doing so. That's a real attempt to send a signal out there that we value reserve resources and, you know, we have a market mechanism for doing so.

In my view, to date, it seems to be working okay. We've gotten relatively robust participation. I think people are still sorting out what the true value of reserves are and what the true cost of providing those reserves are. But, you know, I think one indicator of the success of the market is, have people made changes in their behavior or made investments to provide reserves? The answer to that is clearly yes, antidoticly. The most interesting recent example we had was a relatively inefficient combined cycle unit that's been around for 8 or 10 years. It's been around for a while, so it's not state-of-the-are anymore.

What they did is they offered into the market as two separate GTs the combined cycle portion they decided they might use this summer because the price signals they're getting is that it's more value to provide reserve services than to use their relatively inefficient unit in a market that's long in general capacity, but short in reserve providers. That kind of thing, at least, to me, suggest that things are moving in the right direction. That we are sending incentives and that people are making these operational investment decisions that are good for everybody. We're getting more reserves and they're making more money by providing those reserves. That seems like a win/win to me.

COMMISSIONER KELLY: As the forward reserve market is designed, do you take into account the interest in having transmission or investment in transmission being an alternative? In other words, as you incite quick-start capacity in constrained areas, are you doing it in such a way that, to the extent investment and transmission would be an alternative fix that would be more efficient, that it can happen.

MR. ETHIER: Currently, we don't. Currently, our reserve market in the initial implementation is pool-wide, which basically abstracts from all transmission constraints.

We recognize, at least, we desire to change that and we're actively working on making it more of a location reserve market. We are shortly, I hope, going to enter the stakeholder process with that upgrade and update of the reserve market. At the very least, we'll send an additional signal to these constrained areas that here's another cost that your transmission constraint imposes on your consumers. It gets a little murkier from there, from sending the signal to exactly how you effect the response on the transmission side. That's something all these markets are still working out and we're working with state regulators and with the TOs to figure out how to best make sure that transmission competes efficiently with other sources.

COMMISSIONER KELLY: When you've figured out, will you let us know?

(Laughter.)

COMMISSIONER KELLY: Thanks a lot.

MR. ETHIER: Thank you very much.

MR. PATTON: I was going to say good morning.

(Laughter.)

MR. PATTON: Is there a target timeframe that I should shoot for?

CHAIRMAN WOOD (Presiding): You just go right ahead and talk.

MR. PATTON: I'll try to look up every once in awhile, in case there are questions, but I'll probably go relatively quickly and allow you to ask questions.

This report is somewhat more difficult to process. The Midwest ISO doesn't currently operate a centralized spot market, so that the issues that we focus on in the State-of-the-Market Report are really unique to the ways in which the Midwest ISO facilitates the current bilateral market.

(Slide.)

MR. PATTON: In other words, we focus in in this report on the provision of transmission service and operations and on the operations of the bilateral market. We also have a couple of sections that go ahead to the date

-- what they call the Day Two, which are the LMP spot markets that have been proposed and filed here. I'll be talking a little bit about those analyses as well.

(Slide.)

MR. PATTON: This is an attempt to produce a chart that looks something like one of the charts you saw in Bob's presentation. There aren't many similarities, but what this is, is the on-peak and off-peak bilateral day-ahead prices at the Cinergy.

The on-peak is purple on your screen; the off-peak is blue. We've plotted on that, the natural gas, coal, and fuel oil prices. I think that when you see largely the same pattern or a very similar pattern to what you saw in New England, which is that the natural gas price, which is the one that moves around the most in that figure, plays, by far, the largest role in driving electricity prices.

There are really two or three things you can see in this chart: The on-peak prices are significantly higher than the off-peak, as expected; secondly, that there are the highest monthly prices, or there is an increase in monthly prices in July and August, as you would expect.

But the highest prices, actually 2003, occurred during February, and it's driven almost entirely by the natural gas price increases. So those prices were actually higher on a monthly average basis than the prices in August.

MR. HEDERMAN: David, there is one point I'd like to ask about there. The off-peak prices are varying, it looks like, with the gas also. Is that a new development, or has gas been on the margin in off-peak in a notable way in Winter?

MR. PATTON: It doesn't vary nearly as much as with the gas price, once you get into the Summer and the Fall, so you can see the move up in prices in May and June would correspond to moves down and off-peak prices.

Where it does correspond somewhat is in February and March. That's because there's a smaller difference between the load in off-peak hours and peak hours, since the heating load can be actually higher at night with colder temperatures, so gas units do tend to be on the margin more in off-peak hours in that season.

(Slide.)

MR. PATTON: Moving to the next figure right there, this shows you the capacity in the Midwest ISO for five subregions. The first bar corresponds to roughly half the resources, and is ECAR. The rest of the resources are distributed between MAPP and MAIN and the Wisconsin/Upper Michigan area.

Close to 60 percent of the generation in the Midwest ISO is coal-fired. Only 16 percent is natural-gas-fired, but it does to be on the margin, setting prices at in a much higher percentage of the hours than that, because the coal resources are generally more base-loaded.

Also, virtually all of the new capacity is gas in the Midwest ISO area. There's about 3200 megawatts of net increase in total resources in 2003. It's the investment less the retirements in the region. Next slide.

(Slide.)

MR. PATTON: These are market concentrations statistics. These I'm presenting to give you an idea of the concentration in various areas, although I would caveat this with the notion that concentration statistics are not a great way to measure whether there's market power, because you can see that MISO-wide, the concentration is 261. If you had a monopolist, it would 10,000.

That's extremely de-concentrated, but when you go to some of the smaller areas, the concentration can be quite a bit higher, and in the Wisconsin and Upper Michigan area, it's 2600, which is in the highly-concentrated range.

To get a better handle on actual market power concerns, though, the better structural analysis is the pivotal supplier analysis, and I'll talk a little bit about a section of this report that does a pivotal supplier analysis related to these constrained areas, a little bit later.

(Slide.)

MR. PATTON: If we move to the next figure, this is a load duration curve. We only have hourly loads for 2003, so there's not a year-to-year comparison. But I think it's interesting to point out the pattern that you see here in all of our load duration curves, and that is that -- by the way, a load duration curve shows you the number of hours on the X-axis, that the load is at or above the level on the Y-axis.

So, here, you may not be able to see it. I've drawn a vertical line at 400 hours, around 400 hours, which is the top five percent of the load hours. I've shown you a load of approximately 78 gigawatts.

If you move from there to the very top hour, the load is more like 97 gigawatts, so you can see that there's a 25-percent difference in the load level between the top hour and the 95th percentile. On top of that, you need reserves over and above the peak.

What this tells you is that in the Midwest ISO and everyplace else, you have something like 30 percent of your generation that only exists to serve five percent of the hours or less, or reserves, which -- what you should draw from that is that the pricing in these tight hours plays an extremely and the pricing reserve markets and having reserve markets plays an extremely important role in covering the costs of the units that you need on the system for reliability, and capacity markets serve as a supplement to that.

(Slide.)

MR. PATTON: The next figure shows you the bilateral market prices around the blackout in 2003. There's a shaded area that shows you the blackout.

The dip down in prices that occurs about every seven days is the weekend prices. They are essentially off-peak prices, so they are systematically lower.

What we see, looking at multiple sources of prices, is that on the Friday after the blackout, prices were about $7 a megawatt higher than the previous day. When you go the weekend, prices were about $20 a megawatt hour higher than they were in prior weekends, which is not unexpected, given the uncertainty about the supply resources, because the weekend was during the restoration process, and there was significant uncertainty about how quickly the load was going to come back and resources were going to come back.

In addition to that sort of general review of the prices, we monitored throughout the process, the outages that were claimed and the performance of the generators in restoring. We found no evidence of strategic behavior or an attempt to manipulate prices during that timeframe.

COMMISSIONER BROWNELL: Did you find any evidence at all that the suggestion that competition somehow contributed to or caused the blackout?

MR. PATTON: I was hoping you would ask that question.

(Laughter.)

MR. PATTON: I actually thought the answer your staff gave three weeks ago was pretty good, but I'm going to be somewhat more forceful. In my opinion, the operation -- and I'll talk about this some when we talk about the TLR process.

The operation of RTO spot markets, particularly LMP markets, significantly reduces the potential for this kind of event, because the market software is instantaneously redispatching generation, so that when you approach a limit, there's a constant monitoring and a constant redispatch to manage the loads on the key facilities.

Whereas, in the TLR process, you're asking operators to make forecasts an hour ahead, with significant uncertainty. The transactions you cut are control area-to-control area. You don't really know which generation is going to move, so you don't really know how much relief you're going to get on the constraint that you're worried about.

So, my answer would be that deregulation and, in particular, LMP markets, have a reliability benefit. The other thing that you could say is that it allows you to more fully utilize your transmission.

Because of the uncertainties in the TLR process, you have to operate more conservatively and further away from the limits for LMP, because you have a much greater degree of control over the flows over all of the facilities, and it allows you to operate closer to the limits.

COMMISSIONER KELLY: David, have we seen that in action yet in any market in the country? And is there a way to identify it? Could we study it, measure it, report it?

MR. PATTON: Sure. You're asking someone who makes a living by studying things. If we can study it, yes.

(Laughter.)

MR. PATTON: Yes, we see it in a number of ways. In the LMP markets, the kind of analyses we do where we look at the extent to which flows exceed the limits, you just almost never see that, because the market models are redispatching where you'll see in some of the scatter plots in our report, there are hours where the flow gets over the target in the MISO.

You see a very interesting thing, which is that the operators in the LMP markets in the Northeast do use higher limits, and, in particular, in areas like New York, depending on what generation is available, because they know it can be called on quickly and dispatched through the LMP process, they will actually use sort of emergency limits to allow for more flow and better utilization of the key interfaces like the one into New York City.

So I don't know how you would quantify it, but I do have an analysis that I'll talk about in just a minute that quantifies the difference in at least one respect that I think you'll find interesting.

(Slide.)

MR. PATTON: The next figure is a bar chart that shows you the disposition of transmission requests that were made. The little skeleton bar at the top is the quantity of requests that were refused. The solid bars, the tall solid bars, are the requests that were approved and confirmed.

It's broken out between two types of requests -- redirected service, and I say non-redirected. I think of it as new service. "Redirected" means I already had a transmission reservation, and I'm changing the point where it ends.

What you can see from this chart is that the percent that's refused is relatively low; that quantities that are approved and confirmed have been increasing, so, in general, I think you can conclude that transmission has been available, which is good, because this is the manner in which the bilateral market is facilitated.

We've looked, in particular, at the redirected service, because when somebody redirects service, the revenue from the service goes to the new sink, so somebody, say, the marketing entity who has a transmission affiliate, can redirect service to the control area and retain the revenue, which gives them, in our minds, a competitive advantage over unaffiliated participants.

We haven't seen that that's been a big problem, even though the redirected amounts have gone up somewhat. The amount that's redirected back to the affiliates' control area is only about a quarter of that, so, in most cases, they're probably redirecting it to just engage in some other type of business.

Nevertheless, we think it's an issue that ought to be considered by the MISO.

(Slide.)

MR. PATTON: The next figure evaluates unconfirmed, approved transmission requests. This is a fairly interesting outcome of the rules that govern Order 888-type service, which is that you can request service, get it approved, and you have some timeframe before you confirm it.

If you don't confirm it, it's released, but during that period of time from the time you put in the request, till the time it's withdrawn, the available transmission that other people can ask for, goes down. This was actually a policy that was explicit in Order 888(a) or one of the followup Orders to Order 888, that the Commission wants it to work that way.

What that does is, they don't have to pay for it unless they confirm it, so they're getting a call on firm transmission, so I can reserve transmission between myself and some potentially attractive market and in the period of time when I've gotten approved but not confirmed, I can wait to see if it's going to be economic for me to use it. Nobody else can use it during that timeframe.

The one issue that that potentially raises is that you can do this deliberately to hoard transmission. Like, I could have a computer program set up so that immediately upon my service being withdrawn, I put in another request and the time starts over again, so that I can just continuously occupy transmission that nobody ever gets paid for.

So we employ some criteria to determine whether this activity, in this case, daily firm, point-to-point service, looks like hoarding. What we find is that an extraordinarily small portion of these unconfirmed requests look like an attempt to hoard transmission and keep other people from blocking access to other participants.

This is, again, one of them. Nevertheless, we recommend that some mechanism be considered, either charging a fee for service that you requested and not confirmed, or potentially looking at ways of not debiting the available transmission until they confirm it, to allow the participants to come in, who know they want it, and get it.

COMMISSIONER BROWNELL: Did you drill down? Even though it may not be prohibited, did you drill down in some of the areas where you thought that, potentially, there was hoarding, and did you see anything?

MR. PATTON: That's why we used our criterion. There are some figures that lay out why we chose the criteria we did, how it works itself out. It turns out that a lot of the activities focused on a very small number of paths. This is generally the daily, firm, point-to-point, and is generally between Cinergy and TVA.

There is yearly behavior, similar consequence between AEP and IMO, which is the path that goes through MISO, where you see a lot of the activity focused on that path. The kind of things we are looking for is that the available transmission during the period where other people would be setting up deals, was zero.

Requests were being refused along that path, and that ultimately at the end of the cycle, transmission was made available because they failed to confirm the request.

If you pass those tests, we call it potential hoarding. If you don't pass those tests, what that means is transmission continuing to be available, or there weren't competing suppliers that were having requests refused along the path where you were holding this transmission.

I mean, the fact that we don't conclude that it's hoarding, I think it still can unintentionally block access to transmission on sort of a random basis, and I know at least one of the Board members that heard this talk at the MISO group, who is from the Finance Committee, the minute I said "free call option on transmission," said, well, we've got to do something about that. You can't sell something for nothing, which is essentially what we're doing.

That ends the transmission service, and now we're going to go to transmission operations and look at TLRs.

(Slide.)

MR. PATTON: If you move to the next figure, this shows you TLRs in 2002 and 2003. The royal blue blocks at the top of the stack in 2003, those are TLR-5s, where we're curtailing firm transmission service, so those are more severe events and result in higher levels of curtailments, which are show in the line that's on top of these bars, so the curtailments were higher.

The TLR activity in MISO represents slightly less than two-thirds or 62 percent of the TLRS in the Eastern

Interconnect. That's not terribly surprising. You wouldn't expect TLRs in the LMP markets, so it is a relatively high portion, though, of the Eastern Interconnect.

The most notable increases in TLR activity occurred in the Upper Peninsula of Michigan where the outage of important plants there caused persistent overloads on the transmission going into the Upper Peninsula, which resulted in TLR-5s almost daily until that plant came back.

Secondly, in Iowa, we had a number of TLR-5s. Those were related to two things: One is a bad hydro year in Manitoba, so that the regional flows were significantly different than expected, secondly, there are significant loop flow issues in the Iowa area related to entities doing business outside of the MISO.

In the MAPP region, that caused loadings on the MISO facilities and can result in TLRs, so the two analyses we do of the TLRs, that sort of describes what occurred. The two most important analyses that we do of these are: Is MISO calling TLRs in a reasonable and justified fashion?

That's the area of market monitoring that's really focused on the RTO itself, as opposed to behavior of participants.

(Slide.)

MR. PATTON: If you go to the next figure, this will show you the distribution of over- and under-curtailments and those that we label as accurate. A curtailment is an under-curtailment, in other words, they didn't cut enough, if the flow is over 100 percent of the limit on the flowgate; it's an over-curtailment if the flow is less than 95 percent of the limit, because that's the target.

When they actually call a TLR, they call it to try to actually get to the 95-percent level because of the uncertainties we talked about.

CHAIRMAN WOOD: David, who sets the limit? Does it change over time? Does it change with temperature. Who sets that limit?

MR. PATTON: It's set through an analytical -- basically a modeling process that models -- you have the physical ratings, and it's MISO, by the way -- you have the physical ratings.

CHAIRMAN WOOD: It's done by MISO?

MR. PATTON: Who sets it.

CHAIRMAN WOOD: The ratings that feed into the determination, the physical ratings, are those determined by the TO, or, again, by MISO?

MR. PATTON: Generally the TOs, and the MISO would review the data coming in, but the rating is not the limit. The modeling you do is to evaluate how much flow is going to go over the facility when the contingency occurs, and so they model a set of contingencies that then cause them to operate to a limit that's lower than the physical limit.

And they are using a state estimator to try to accurately adjust those ratings in real time. In terms of what this shows, I label as accurate, over- or under-curtailments that are within one percent of those levels, and that's 40 percent of the TLR activity.

If you go to five percent, flows that are between 90 and 105 percent, you pick up 86 percent of the TLRs, so our conclusion is that the TLR process has been reasonably implemented. The use of a state estimator in the MISO will further improve this performance, but that shouldn't make you feel great about the TLR process; that should make you feel okay about how it's being implemented.

(Slide.)

MR. PATTON: If you go to the next, these are really the key conclusions with regard to the TLR process and its implications. This summarizes a number of analyses in the report.

The three points are: If you look at the amount of curtailments that occur through the TLR process, versus what you would have had or redispatched through an LMP process to manage the same congestion, we're curtailing three times as many megawatts through TLRs, basically because it's an indiscriminate way of managing the congestion, as opposed to a much more discriminating mechanism.

That suggests that the LMP markets that the MISO is pursuing, will have significant efficiency benefits. Secondly, the current bilateral energy prices that we've looked at, don't do a very good job of accurately showing the congestion that occurs on an hour-to-hour basis.

When you look at price differences between upstream and downstream locations, when TLRs are being called, for example, LMPs, again, will improve the transparency of the price signals.

Thirdly, there is the point regarding the potential reliability of benefits and the improved utilization of the transmission system that you can get by moving to a central dispatch process, versus the TLR process that we talked about in the context of the blackout a minute ago.

(Slide.)

MR. PATTON: Quickly, this is an evaluation of the available flowgate capability that is calculated by the Midwest ISO. What we look at here is the hourly, non-firm flowgate capability.

The reason we look at the hourly non-firm is the goal would be that the space that is physically available on the flowgates, looks a lot like the hourly available flowgate capability, so that if there is unused capability, people can come in on hourly, non-firm basis and use it to transact. So, we essentially compare the difference between the flows and the limits on the flowgates against the hourly non-firm or in hours where the hourly non-firm AFC is posted at zero.

So, the MISO is saying that there's no capability. What we find is that roughly a quarter of the time, that AFC posting is relatively accurate. Close to half of the time, there's 30 percent or more of the flowgate that's actually available when the MISO's posting is zero.

Essentially that's because the models don't have accurate information when they are calculating the AFC or information that is as up to date as it could be. Our recommendation is to better utilize the state estimator results that tell you what the flows are on all your flowgates to post more accurate, hourly, non-firm values.

(Slide.)

MR. PATTON: The last area we're going to talk about is the market power analysis.

CHAIRMAN WOOD: Just to clarify, as I recall, the state estimator was really fully operational early in 04, correct? So this data from 03 would be all pre-state estimator use?

MR. PATTON: It's been in operation, but perhaps not wholly functional until early 04. In fact, they started to interact the AFCs with the state estimator results in December of 03.

We've done some analysis on how big the improvement has been in the AFC values following that, and it hasn't been tremendous, the improvement, into early 04, so we think there's still room to improve.

(Slide.)

MR. PATTON: This summarizes the market power analysis, which is the pivotal supplier testing that we've done. This is done on a constraint-by-constraint basis, so there's a section in the report that looks for transmission constraints within the Midwest ISO.

Where there are one or more suppliers, the resources have to be used in order to resolve a given transmission constraint, so with regard to that constraint, they are essentially a monopolist, and it plays into the structuring of the mitigation measures proposed to address the problems that are identified as coming out of this type of analysis.

MR. PATTON: In summary, what we essentially find is that most of the transmission constraints that exhibit one or more pivotal suppliers are constraints that effect flows into the Wisconsin, upper Michigan area. Some of them are located in Iowa, so they can effect other flows as well and measures have already been proposed that I consider to be important to address the implications of these findings, which I think you are currently reviewing.

That was all I was going to address in the talk. But I'd be happy to take questions on the state of development of the Day Two markes or any other issues that I skipped over.

CHAIRMAN WOOD: Any questions for David?

(No response.)

CHAIRMAN WOOD: I had just one. One of the ones I think you indicated was kind of your pivotal area here as far as congestion and inability to get power in and out. Is MISO contemplating, as we see in the other regions of the country, some sort of demand response program administered on the wholesale market side of the fence that would allow there to be some, perhaps, offset to some of the demand supply analysis in that market?

MR. PATTON: I know they've been discussing that. It's at a relatively formative stage. It's not as far along as the proposed markets at this point.

CHAIRMAN WOOD: It's hard to make markets work if the third leg on the stool is not in there. Duration and transmissions are going to take several years to get up, as we've heard from the state regulators and the parties. In Wisconsin, demand response is pretty darn fast.

MR. PATTON: Yes. In fact, demand response can be done relatively quickly. The emergency program in New York, I think, works relatively well. It's a mechanic to pay to demand responders. I think through that sort of mechanism you can overcome some of the regulatory incentives that prevent demand from seeing the price and having an incentive to respond to it. I think probably as important or even more important, in MISO, in terms of future development, is the introduction of reserve markets. Those play a key role, particularly, in the constrained areas because you operate with reserve requirements. Until you make them market requirements, you end up with things that distort the signals like operators committing generation and paying uplift and no signals and generators who then require RMR contracts. There are those sorts of issues.

(Laughter.)

MR. PATTON: So I think the move towards the reserve markets is important as well.

MS. SHEFFRIN: Moving westward.

CHAIRMAN WOOD: Here we go.

MS. SHEFFRIN: Good afternoon. Thank you very much for inviting us here today.

CHAIRMAN WOOD: Glad to have you back.

MS. SHEFFRIN: I'm Ani Sheffrin, Director of Market Analysis at the California ISO. I have with me Greg Cook, Manager of Market Long Term. He and his staff put together the annual review of market performance, which we filed with the Commission just last week. He will be here to assist me in answering any questions that you have.

CHAIRMAN WOOD: Welcome.

MS. SHEFFRIN: I will present the highlights of market performance for 2003 as well as the standard metrics that the staff requested as to present from each of the ISOs.

(Slide.)

On Slide 2, let me just start with a quick background. On the California markets, unlike the eastern ISOs, we did not evolve from a tight power pool that had been operating for decades. There were three separate control areas in California before the ISO started. That was PG&E, Southern California Edison and San Diego Gas & Electric. They all merged into one control area and we serve the customers of each of those utilities as well as municipal utilities, both in northern and southern California.

As you all know, California is very much interconnected with the rest of the West. We operate within the western connection and are very much dependent on imports that comes from those other regions. Our peak in California was 42,581 megawatts. That occurred on July 3, 2003. On that peak day, we had about 42,000 megawatts of installed capacity available. That accounts, after the derates, for hydro that occur as well as the outages for maintenance that can occur. Because the PK can occur any day during the summer, we imported on the peak hour 5670 megawatts.

(Slide.)

In terms of the current markets, the ISO operates -- they're a little bit different than the eastern ISOs. We have a real-time imbalance market. We also manage congestion through markets. Day-ahead and hour-ahead, but on a zonal basis, not LMP yet. We acquire the full set of ancillary reserve services, regulations spin, non-spin and replacement. We have a soft price cap of $250 in place, though it was only hit once last year because we had very good market performance. We also have automated bid mitigation procedures in place again. Just because of good market performance, they were never triggered on a system level last year.

We do not have a day-ahead energy market, as you know. The power exchange went out of business in 2001, so most of the transactions occur on a bilateral basis until we get a formal day-ahead energy market running again.

(Slide.)

Let me turn to the market highlights. I am very pleased to report that California turned in a stable market performance for two years in a row with very competitive market outcomes. So that certainly made our jobs much easier. This was due to ample supply of new generation that came online. We had a good level of hydro and good imports. And, as well, we had moderate loads. So all of those factors helped contribute to good market prices and good outcomes.

As I said, we did not mitigate any prices in 2003 for system reasons.

COMMISSIONER BROWNELL: Ani, you said ample supply coming online, and maybe you'll say more about that later, is that in California? Is it in the neighborhood? Will import dependence continue and is anything retiring?

MS. SHEFFRIN: I do have a slide on that.

COMMISSIONER BROWNELL: Okay.

MS. SHEFFRIN: You will hear the same story in California as you heard in the other ISOs. Industry price has increased in 2003, mainly, due to the increase in natural prices. Real-time prices averaged $70 a megawatt hour, but our volumes were very low in real-time because the utilities really relied on their contracts and bilateral purchases and soft supply to meet most of their needs, so we had small volumes in our real-time market. Our ancillary reserve prices averaged $9.85 a megawatt hour. That was a 38 percent increase from 2002.

We did have some hours of insufficient bids and so we had to rely on -- the reliability must run to meet the rest of our reserves. And I will talk a little bit more about that in my presentation.

Finally, the one area that we are concentrating a lot of effort on is the real-time interzonal congestion because it has to be managed in real-time at certain locations. We are looking at better ways to manage that. The reason we had so much real-time intrazonal congestion this year compared to last year is we had some relatively big outages at some large substations.

The Vinson substation had a fire. The Solmar substation had substantial work done on it. That created some of the intrazonal congestion. The other part came from just facility overloading at the Miguel plant due to generation coming on in northern Mexico and in Arizona.

COMMISSIONER KELLY: Ani, I know this is about 2003, but I can't help but ask about 2004 and the last couple of weeks. Did you see prices hitting the soft price cap and did you need any mitigation?

MS. SHEFFRIN: No, we didn't. We saw some high prices this last Monday because it was so hot in southern California. We have some again very specific locational congestion in southern California. The prices hit $180 for about three hours.

COMMISSIONER KELLY: Thanks.

(Slide.)

MS. SHEFFRIN: On Slide 5, we've been tracking total wholesale energy costs to serve loads since the market started. And, again, on Slide 5, you see the last two years, 2002, 2003 being much lower than during the crisis period. 2003 is $12.1 billion to serve wholesale cost in our control area compared to $10.1 billion in 2002. Most of that is attributable to the natural gas price increases.

(Slide.)

On Slide 6, I have the first of the standard matrices. That the all-in price very similar to what Bob Ethier presented. Our all-in price in 2002 was $45 a megawatt hour. In 2003, that rose to $55 a megawatt hour. The largest component was the energy component because of natural gas price increases. The other components are a little bit hard to see, but in a very colorful table to the right, essentially, the biggest components after the bilateral energy prices and real-time energy prices because of natural gas increase were the intrazonal congestion costs where we had to keep units on minimum load, pay them minimum load cost compensation as well as increase some RMR costs because of locational congestion.

(Slide.)

We have the real-time incremental energy prices compared to natural gas prices and the red is the prices in northern California. The blue are the prices in southern California. And, as you can see, the prices in the market pretty much followed the real-time price. You had higher prices in southern California because there are more locational transmission constraints and because load is growing very fast in southern California as well.

(Slide.)

We have the top 5 percent of the hours graph for you. And, again, we are comparing 2001, 2002 and 2003. 2003 is the blue line and it's the middle. Certainly, it's below what we saw in 2001, but it is higher than last year where prices are at $150 or greater. We had 25 hours of that in 2003. Factor in the price signals, it was 2553 hours, so things have definitely settled down and have improved quite a bit.

(Slide.)

Slide 9 shows the load situation. Loads grew, overall, only 1 percent from 2002 to 2003, but we track the numbers monthly, which gives us a better indication. And, since the last part of the year, we've seen an up tick in the economy and loads growing more in the order of about 3.7 percent a year. So the economy recovery is showing itself in terms of higher consumption levels.

(Slide.)

We have another one of the standard metrics and that's the forced outage rate. We've seen improvements in the forced outage rates where they were highest in 2001. They've come down to 4 percent in 2003. The only thing I would not is the number in 1999 probably isn't the most accurate one because outages were only voluntarily reported in 1999. Now a mandatory reporting requirement for averages in our control area. So we have more confidence in the numbers for 2001 than 1999, but we're happy to see the reduced forced outage. That was part of the supply that was available to meet load and to moderate prices.

MR. HEDERMAN: Ani, on that, there was a little confusion around the discussion on generator behavior. I'd just like to give you an opportunity to kind of clarify your take on that, at this point, in terms of were we seeing anything in generator behavior that we're concerned about?

MS. SHEFFRIN: No. We're very pleased with the reduction in forced outage rates. Our compliance with the operating instructions is very good. So only good news to report on that.

MR. LARCAMP: Is there a relationship between the number of hours that the marginal units were called to run? Is there a relationship here between the decreasing load and good hydro for the last couple of years?

MS. SHEFFRIN: Certainly.

MR. LARCAMP: I guess that's amplifying on your ample supply commentary?

MS. SHEFFRIN: Right. There may be some relationship. You know, people can say, well, because the units weren't called on as much, they didn't break down as often, you know. I really think that if people are getting high prices, they have a lot of incentive to keep units on. The improved forced outage rate really is due to improved outage coordination and reporting processes.

(Slide.)

A key factor to continue improvement in the market performance has to be the investment in the infrastructure, both in transmission and generation. This is, I think, the slide that, Commissioner Brownell, you asked about. These are the number of new transmission projects that have been approved, the highest level on an annual bases in 2003 is $752 million, 24 projects approved. We are looking for a higher number of projects, though, a lower value in 2004.

These are mainly reliability projects, but they do have some economic-driven transmission projects and we're pretty aggressive in California trying to make sure that we've got that transmission infrastructure since we're so highly dependent on it to be in place.

COMMISSIONER BROWNELL: Does approved mean they're getting built?

MS. SHEFFRIN: Approved by the ISO. They may not be built in the year that they're approved because they may have another -- most of them are getting built. There's a couple that may need some sitting at the CPUC, but we're working with the CPUC to help expedite that process. So most of them, yes, I would say are being built.

CHAIRMAN WOOD: When you work with those, will you get a copy for us of what projects you all have approved through the ISO. And, if there are any ones that are kind of being held back because of this kind of review, we can, perhaps, work with the PUC there to help support.

MS. SHEFFRIN: Sure. I think we just put out a report on our web, a good planning study, which I believe has that information.

CHAIRMAN WOOD: We'll get that.

MS. SHEFFRIN: In terms of generating capacity and net additions, we've had quite a few new additions come on in 2003. 480 megawatts came in, in 2003. We also, though, had significant retirements, 2152 megawatts of retirements. So the net total increase in 2003 was 2678. In 2004, we expect about 580 megawatts of capacity additions. Looking on in 2005, there are about 4000 megawatts that are in construction, but I believe they are awaiting getting a long-term contract to finish that construction. So, again, resource adequacy is a very critical part of bring new generation on to meet the growing load.

COMMISSIONER KELLIHER: Excuse me. When you referred to 4000 megawatts under constructions, do you mean 4000 megawatts that are licensed?

MS. SHEFFRIN: They've been permitted already and the financing hasn't gone through. I believe a lot of them are in the CPUC procurement process. Hopefully, the utilities will pick them up as part of their procurement.

COMMISSIONER KELLIHER: But isn't any construction already taking place at those plants?

MS. SHEFFRIN: Some things like Mountain View are under construction. So there are about 4000 that have already been committed and in construction. Some of them have contracts and will finish. Others, I think, are awaiting the results of the procurement to finish their financing and complete construction.

COMMISSIONER KELLIHER: But when, say, a plant developer announces their intent to forego construction for a certain period of time, that plant is still in your 4000 under construction?

MS. SHEFFRIN: For next year, right.

COMMISSIONER KELLY: Ani, regarding new transmission projects in 2000 to 2002, there was a big jump in the number of projects approved. Did FERC's westwide removing obstacles order play any part in that or was that increased due to other reasons?

MS. SHEFFRIN: We'll have to get back to you and check with our transmission planners and get back to you on that.

MR. LARCAMP: I think there was only one transmission project that qualified for the financial incentives.

(Slide.)

MS. SHEFFRIN: On Slide 12, another key factor on market performance was the continued level of imports at a high level in 2003. We had approximately 6000 megawatts on average that was imported into California. The result of new investment reduced outages on the existing plants as well as a high level of imports meant that we had a moderate markup of prices above a competitive baseline and that's what I show in the next slide.

(Slide.)

Positive factors lead to very competitive results. This was reflected in the price cost markup, which was in the 7 to 8 percent region. So, again, this was very steady throughout the year and gave us confident that the market results that we were showing were very competitive.

(Slide.)

On Slide 14 --

COMMISSIONER KELLY: Ani, can we go to Slide 12? This slide seems to show that power imports are very important to California. Has the planning process in California relied appropriately or too heavily on imported power, do you think?

MS. SHEFFRIN: You know California has always been a net importer of power and I think we are forward-looking enough to make sure that we have the transmission lines that can access that. About 8000 megawatts of new plants came on in the Labada and Paloverde region. Some of them in hopes of importing their power to California.

COMMISSIONER KELLY: And, when you take into account the importation from another state, do you look at the demand for that power in the other states?

MS. SHEFFRIN: With resource adequacy, we should. That is a very important part. If everybody is sort of drawing straws from the same pool, you begin to worry. But, with resource adequacy and utilities identifying what they're going to rely on and demonstrating that they have a contract that shows that they have the right to call upon that power, I think that will greatly help the situation.

Too many sucking at the same supply line --

CHAIRMAN WOOD: Does the current resource adequacy proposal from the Commission nail that all down as far as the import wherever the capacity is coming from?

MS. SHEFFRIN: Yes. We've requested that it show what the source of that capacity is. We'd like to see the contract for that capacity as well as showing the deliverability requirements. We think those are all key components of the resource adequacy. It's got to actually get to load to be counted and those are the proceedings that we're in discussion with at the CPUC, letting them know what our requirements are. So, when they ask the utilities to acquire resources, they know all the characteristics that are critical for the ISO then to operate the grid.

COMMISSIONER KELLY: Along the line of that deliverability requirement, does the ISO look at the transmission capability for import purposes?

MS. SHEFFRIN: Yes.

COMMISSIONER KELLY: Has sufficient investment been made in the transmission capability for import purposes, in your opinion?

MS. SHEFFRIN: You know, the market results show that the intrazonal congestion at Miguel, there are critical areas that need to be upgraded. We may have the capacity or the pipeline to come into California, but then internal to California there may be a constraint at a substation. We're trying to identify those and get those upgrades in place.

COMMISSIONER KELLY: Thank you.

COMMISSIONER BROWNELL: It would be helpful maybe, Ani, if you could give us some more details on the upgrades that have been approved and their status. I had heard some contrary information about the ability to import from Nevada and New Mexico. So, obviously,w e need some more current information, maybe divided into kind of two categories, what is being done to address import capacity from other states and regions and what is being done internally? I'm not clear from the chart, actually, how you make that distinction and I'm not clear in terms of that approved and done part.

MS. SHEFFRIN: Sure.

MR. LARCAMP: I believe Edison recently sent some information to the Commission about an expansion of the Paloverde. As I recall, that's well outside the 08's timeframe for implementation of resource adequacy requirements. Under the existing CPUC requirements, they are looking to expand into Arizona to Paloverde, but that time line is much further out in the future, at least, in the documents that Edison sent into the Commission.

MS. SHEFFRIN: Commissioner Brownell, your question was that you'd heard there were some impediments to getting that power delivered and I'm agreeing with you that there are. We're trying to identify those.

COMMISSIONER BROWNELL: I thought you said there was sufficient capacity?

COMMISSIONER KELLIHER: With the 8000 megawatts that have been built in Nevada or Arizona, it sort of begged the question, was there a related increase in the transmission capacity, perhaps, not?

MS. SHEFFRIN: What I meant to say, if I wasn't clear, I'm sorry, there are some local bottlenecks, such as the Miguel substation that need to be upgraded. Some other local bottlenecks, like south of Lugo. Again, so that power is flowing into California, but it may not be able to be delivered to all the locations of load. It can get into the state, but not all the locations of load because of localized constraints.

COMMISSIONER BROWNELL: I understood that. What I don't understand is kind of this future dependence on imports and my understanding was that there's not sufficient capacity, even to get it into California. So two different questions, intraCalifornia and inter.

MR. COOK: I think to add a little detail to this, the main pathway for getting imports into California from the southwest is the Paloverde intertie. When you look at 2003, that intertie was congested 6 1/2 percent of the hours of the year. Those are generally during peak hours. That frequency of congestion has increased over 2002 and we have seen increase on some other paths also into California, also, coming in from the northwest as well.

MS. SHEFFRIN: But 6 1/2 percent of the hours is not a huge number of hours.

COMMISSIONER BROWNELL: I think that I'm not making clear -- I'm not talking about today or tomorrow. I'm talking about a growth that's now 3.7 percent and anticipating, assuming the economy remains strong, how that future planning is going. Because one of the issues that we're all worried about all the time about California is the future planning. So 2003 is great, 6 1/2 isn't much. But what is it next year and the year after that?

MS. SHEFFRIN: Absolutely. Several agencies in California have gotten together to look at the future supply. The California Energy Commission certainly has a lead role in looking at that. We have a substantive effort in the transmission planning area to take a look at our next 10- or 15-year needs, so we are working on that effort. And I'd love to send you a report on that.

CHAIRMAN WOOD: What's the timeframe on that?

MS. SHEFFRIN: We have to file that at the California Public Utilities Commission by June 3rd. That is an economic evaluation to identify needed transmission facilities. The hope there is to streamline that process so a specialized need assessment doesn't have to be done for every line, project proponents -- sort of formula that they can apply and use on a particular projected upgrade. Then file that at the Commission and know that the ISO will agree with that procedure. So we're trying to streamline that whole sitting process for transmission.

COMMISSIONER KELLIHER: I just want to be very clear on something you talked about earlier, the new transmission project figures you provide. The total number of projects is something like 300 that you list here, but these are projects the ISO believes are needed. Right? It's an entirely separate question to what extent they've been approved by the CPUC.

MS. SHEFFRIN: Whatever I may have said, I may have said it too quickly. A lot of these are reliability projects, which really don't require any new siting, so the ISO is the last stage to approve it.

Then the utility goes ahead and puts it in, only if it needs siting, a new line, a new footprint, and then it goes the California Public Utilities Commission. So I would say that the large majority of these are going to be accomplished because they just need our authorization.

We approve them. We say, yes, there is a reliability need, and they are just done by the utilities.

COMMISSIONER KELLIHER: When you say that they are going to be accomplished, the projects from '89 -- I mean, '98 and 2000, are they underway?

MS. SHEFFRIN: Oh, yes. We just sent to our Board, a grid reliability study in which it sort of lists out the upgrades that have been approved and are enjoyed in each of the regions, each of the critical regions.

COMMISSIONER KELLIHER: So nearly $2.5 billion is currently and has been invested in the transmission system in California?

MS. SHEFFRIN: Yes.

COMMISSIONER KELLIHER: Thank you.

COMMISSIONER BROWNELL: Has Project Rainbow been approved?

MS. SHEFFRIN: Valley Rainbow was rejected by the California Public Service Commission.

MR. CUPITA: Can you talk a little bit about the prospects for Mexican power coming into California, and what the status of those transmission lines is?

MS. SHEFFRIN: There are a number of upgrades that are going to be done at Miguel to help improve that power coming through at the Miguel Substation. A second transformer bank has been put in, as well as some series of capacitors that should increase the capacity by about 350 megawatts by December of 2004, the end of this year.

Then there is going to be a second Miguel transmission line that's going to be built. That should increase the capacity another 650 megawatts. That is before the CPUC, because it did require some siting, and as soon as they are through and have approved that project, that will take about a year or a year and a half for construction, so a total upgrade of about 950 megawatts in the next couple of years.

(Slide.)

MS. SHEFFRIN: Let me go back to the price/cost markup. Again, we saw competitive results, both in Northern and Southern California, with a markup of about seven to eight percent. That's well within the normal range of just measurement errors, as Bob talked about it.

So, we're seeing very competitive results in that.

(Slide.)

MS. SHEFFRIN: In Slide 14, what I do is give an assessment of the pivotal supplier index. We call that the residual supply index, and it's simply, if you remove the largest supplier in every hour, then could demand be met with the rest of the supply in the market?

If the answer is yes, that means that a supplier probably doesn't have too much market power and the ability to set market prices, so an RSI index above one or 100 percent in Bob's work, means that supplier is not pivotal, so the higher the RSI, the better.

Again, in 2003, we saw some of the highest RSIs where the number of hours of RSI was less than the one that was only 22 in the year 2003, but in 2001, it was well over one-third of the hours, so, that's certainly a structural improvement with the ample supply coming on in the market.

(Slide.)

MS. SHEFFRIN: Another very important metric is the net revenue analysis. And that essentially is telling us, given the market prices, is it signalling new investment to come on?

Here, in the blue, we compare the fixed and variable costs of combined-cycle or a combustion turbine on the right-hand side, compared to the revenues that that unit would earn if it strictly relied on spot market revenues from the ISO.

As you can see, between 2002 and 2003, really that profit that goes to fixed costs, fell 30 percent. I think that's in line with what you saw in the other markets as well.

Essentially what that says to us is that market prices will give you a boom-or-bust cycle for generation entry. In order to smooth that out, you really do need a resource adequacy requirement where the utilities have to go out and procure.

Then the generators can use that contract for financing, and that really is the steady-state cycle that you need to go to, and if you just rely on spot market revenues, you're really going to have this boom-or-bust cycle where 2000-2001 was a boom and they over-recovered ten times, but then the next two years were a bust.

Again, in terms of healthy market development, we're very much pushing for resource adequacy as the means to smooth out the boom-bust cycle and generation additions.

CHAIRMAN WOOD: The boom, or, in this case, the purple bars, are the combined-cycle costs, and the CT costs. Bob, I'm just looking at what you have in New England. What's a good number here?

Is it more expensive in New England than in California? I'm looking at your range as 105 to 120 per CC. Here we've got 90 or so. It looks 909 bucks. Is that a good number?

MR. ETHIER: That's a good question. I would say that amongst the ISOs, there's a pretty wide range. My recollection is that PJM's numbers were low, relative to ours, as well.

The flip side is that you talk to our participants, and they think our numbers are low. I just think there's a wide range of expectations there. There is no right number.

CHAIRMAN WOOD: We know what the red number is. We just have to look at that.

MS. SHEFFRIN: And there is a wide range, even within California, depending on where you want to site. There are land costs, transmission interconnection, gas interconnection, all of those can vary.

We used a standard number that came from the California Energy Commission. They collect all the information on plant costs. That was the source.

CHAIRMAN WOOD: Regardless of what that bar is, your point is a good one, that the resource adequacy issue is needed to provide the more steady cash flow. It's just opposed to energy market allowances. You're preaching to the choir on that.

MS. SHEFFRIN: The rest of the slides are just how our other markets performed.

(Slide.)

MS. SHEFFRIN: In Slide 16, we show you prices for each of our regulation, up, down, spin, non-spin, and replacement markets. Prices are up 38 percent, and that's mainly because we had a decline in supply of resources supplying reserves in our market.

CHAIRMAN WOOD: What's that from?

MS. SHEFFRIN: That's because about 2,000 megawatts chose to be on Condition II. That means they don't bid into the market, so previously, the year before, they supplied reserves in the market. They chose as their choice, to have the ISO pay the full cost, and then part of that contract is that they don't participate in the market at all.

That was a loss of reserves for us. We are looking to fix this problem. We're going to be making a filing in the must-offer, where we also have a market rule that says units that are paid their minimum load cost compensation, risk losing that if they bid into the ancillary service market.

We think that is a source of supply that we need. If they're on and they have some capacity, we certainly want them bidding to this market, so we will be filing that rule change with you. We think that will help the supply come back, but again, 2,000 megawatts is out of the market entirely because of being on Condition II for the must-run contracts.

CHAIRMAN WOOD: When do you think you'll file that?

MS. SHEFFRIN: I think we're going to file in the next week. We've been working with the state Code of Processes.

CHAIRMAN WOOD: And you're going to have that in place for the Summer?

MS. SHEFFRIN: Right, so we're hoping that if we file that, then in 60 days, it will be there by early July, and that will be in place.

(Slide.)

MS. SHEFFRIN: Slide 17, Congestion Between Zones, what we saw is really that was reduced quite a bit, 33 percent. The total in 2002 for congestion was $42 million, and in 2003, that went down to $28 million annually. That was a good thing.

On page 18, you see where some of those major congestion lines came from. Path 26 was the most congested at $12 million a year, and, again, that was mainly because of the fire at the Vinson Substation, as well as the work done at the Solmar Substation.

The rest are really below $3.5 million, pretty small amounts of congestion on those other major lines.

COMMISSIONER BROWNELL: And that won't change your assumption because of this growth? How much of this was a reflection of an economy that was still, at best, flat, and, therefore, demand was down?

MS. SHEFFRIN: I think that our intrazonal congestion really isn't the problem; it's more the congestion within certain locations, and trying to get those facilities upgraded. You'll see that on the next page.

In contrast to our interzonal congestion, congestion occurring within the zones, we had a dramatic increase. In 2003, it was $15 million, compared to the $28 million that we just looked at on the other lines.

Certainly, bottlenecks on certain locations are the most problem. That $151 million, that number was only $6 million in 2002, so essentially the majority of it was an increase in congestion at the Miguel substation that had to be managed in real time, and that was because of the new plants coming on in northern Mexico and in Arizona, all coming in, overloading one particular substation.

That is underway, the upgrade is underway. We don't anticipate that will solve the entire problem, but probably about 80 percent of the problem.

COMMISSIONER BROWNELL: The planning process that includes the neighbors didn't pick up here?

MS. SHEFFRIN: Right, because it was internal within California, and really this experience has caused us to take a much more comprehensive review of these bottlenecks, locational bottlenecks.

(Slide.)

MS. SHEFFRIN: My last slide brings me to some of the issues that we've really been working on in 2003. One of our most important priorities is to review and get a more effective means of managing real-time congestion, because it has to be managed in real time. It's not good for the operators to have to worry about so many things, and, with real time, you would have the fewest number of options left.

So, we are going to hopefully look at a couple of ways to manage that, and then be filing with you in 2004 on how to effectively manage real-time congestion.

I talked about the must-offer redesign process. That's going to help our ancillary service bid.

COMMISSIONER KELLY: Regarding that point, real-time congestion management, what categories of changes do you see?

MS. SHEFFRIN: Managing real-time congestion has been a problem, historically, at the ISO. We keep filing, since 1999, on how to manage that and moved it to the day-ahead. You know, you keep pushing us to go to LMP, which is our long-term plan.

In the meantime, we have to limp along, so I think we keep filing things, you keep saying yes to some, no to other, and then we keep refiling. You know, there ought to be another means of doing it, so it's going to be -- we'll have to try again, but, definitely, all this congestion has to be moved out of real time.

So we are looking at some other ways to move it that we'll be filing with the Commission. Hopefully we can have more discussions with the Commission before we file.

COMMISSIONER KELLY: That would be helpful. What's the problem with moving to LMP?

MS. SHEFFRIN: There is no problem. It's our intent, I believe, that we have a comprehensive plan, and we file with you monthly, our progress to try to get that.

The second issue is the must-offer waiver redesign process. That's a very large stakeholder process that we've had underway, which is finishing up, and we hope to be filing that next week with you.

CHAIRMAN WOOD: The one we just talked about?

MS. SHEFFRIN: Right. The third is, we are pursuing very actively, resource adequacy requirements, as well, and that, you know about. Lastly, I've personally been heading up an effort to streamline transmission expansion, just looking at the economics, identifying projects that are most cost-effective, and having standard methodology put in place that anybody can use who is a project advocate, put it in place and have the CPUC stamp it and say, okay, did you use the standard project?

We didn't want to re-litigate that whole thing. We'll get down to the environmental issues and streamline the siting.

CHAIRMAN WOOD: How is the cost of new transmission paid for in the Cal ISO footprint?

MS. SHEFFRIN: The Cal ISO can deem it needed. Then it will get rolled into rate base.

CHAIRMAN WOOD: Rolled into a statewide average, not just the 03 area?

MS. SHEFFRIN: Right. It will be rolled into a statewide access charge, but it doesn't preclude merchant projects as well. So we're trying to have a methodology that, you know, really balances merchant.

CHAIRMAN WOOD: The charges will be just included as part of all the other charges?

MS. SHEFFRIN: TransElect and WAPA are going to upgrade the facility, and then it's going to be rolled into the California-wide access charge.

COMMISSIONER KELLY: Is it contracted for, the new transmission?

MS. SHEFFRIN: Yes.

COMMISSIONER KELLY: Who is on the other side of the contract?

MS. SHEFFRIN: TransElect and WAPA.

COMMISSIONER KELLY: The other side?

MS. SHEFFRIN: The utilities? It's the California ISO. The revenues are going to be paid from the California ISO access charge, so then, you know, in terms of those entities, then can go and sell that, we will give them FTRs. They can go and sell that right to whomever wants to use it.

COMMISSIONER KELLY: So they don't really enter into any contracts with load-serving entities?

MS. SHEFFRIN: The biggest contract is the cost recovery from us.

COMMISSIONER KELLY: Do you enter into a contract with them?

MS. SHEFFRIN: No. We just simply say that we deem these needed, and they will be recovered through costs.

CHAIRMAN WOOD: Actually, we had to approve that; didn't we?

MS. SHEFFRIN: Yes.

CHAIRMAN WOOD: That was unusual, actually. We had one like that before.

MS. SHEFFRIN: I think you approved it very quickly. Everyone knew that there was a bottleneck.

MR. LARCAMP: I don't think that one was certificated.

CHAIRMAN WOOD: It didn't have to be, because that was federal, WAPA. You're going to be doing the economic evaluations that will not only look at the reliability as is what is coming out of the chart that you showed us, that 200-plus projects over the last five years, all really reliability-focused, and this would be kind of looking at the other half of the story?

MS. SHEFFRIN: Right. And then there is Commissioner Brownell's issue of looking forward and making sure we're planning for the future.

The other thing I wanted to just state on the 3.7 percent load growth, is that when coming out of a recovery, it tends to be very steep. Then as the recovery matures, it tends to level off.

I wouldn't want you to walk away with the impression that we're going to get 3.7 percent increase for the next ten years.

COMMISSIONER BROWNELL: It would be lovely if you did, actually. We'd all be happy, but the reality is that there is a long history of whether it's one percent or whatever, of not planning.

We consider it our responsibility to poke and prod, frankly, to make sure that we don't find ourselves in the situation that we have had to deal with in the last couple of years.

MS. SHEFFRIN: Thank you very much.

CHAIRMAN WOOD: Thank you, Anjali. Joe, Sudeen?

(No response.)

CHAIRMAN WOOD: Kind of an exit question: Since we are looking more broadly at the MMU rule and trying to look at that across the country, recognizing that you all are in different places and different markets, but I guess, just as a broad question, what would you consider to be your primary function?

Would it be the analysis/oversight, like we talked about today, or enforcement?

MR. ETHIER: I guess I would go with the former. I think the greatest long-run contribution we can make is evaluating market outcomes and pointing to areas that need improvement. While the enforcement gets a lot of headlines, the transient stuff, in my view, is not as important as getting the fundamentals of the market right, getting the signals right for investment and so forth.

CHAIRMAN WOOD: David, I know your role is different because you're external to the organization, unlike Bob and Ani.

MR. PATTON: But I agree with Bob. I think it's largely the former and I would reinforce that a big and important segment of it is monitoring the operation of the RTO itself to provide confidence to the market participants and to identify procedures that appear to be low levels are related to reliability and not to markets. That can have important interactions. That's an important side of it.

Actually, the enforcement side, which I would separate from mitigation. Mitigation, I think, is less prospective. The enforcement side is actually a side where, I think, appropriately you're playing the more heavy roll through the behavior rules and setting up deterrents against certain conduct, which actually makes me a lot more comfortable than having that be administered through an ISO tariff.

MR. ETHIER: Can I amend my response?

(Laughter.)

MR. ETHIER: And, actually, add to the response, which is to add a third category, basically. I think the ISO, in general, and the market monitor, especially, have a responsibility to provide as much information about the marketplace as possible. These markets are very complex.

Information is very important and the participants only get a very limited slice when they just look at their narrow view of the world. It's our responsibility to do things like this, but, more broadly, to communicate how the markets work, how they're not working and provide as much data as humanly possible so that people make these informed investment decisions, strategy decisions, what have you.

I guess I would add one thing to the component that's right up there with everything else.

CHAIRMAN WOOD: Before Anjali answers, Dave, you mentioned something about mitigation that kind of tickled my brain. What do you mean by that?

MR. PATTON: For example, by mitigation, I mean things like the conduct and impact framework that allows you to identify when a participant's bid should be restricted in some fashion. So prospective, so in an area -- I think last time I was here we talked about how it's somewhat remarkable that a marketing function in New York City where you basically have a number of little monopolies because the constraints are so severe. You want to deal with after-the-fact enforcements being impenetrable. The natural result would be to regulate, but through prospective mitigation, you can allow the market to function. There's a set of conduct that you can't do that with, but can -- to be prospective, it has to be done through penalties like physical withholding because you only know if it occurred after you did an investigation and that sort of after-the-fact enforcement and deterrent, which is a distinctly different approach than the prospective. When you have to employ that, I think it makes a lot of sense to have the Commission really be the lead and have the market monitors provide information and inform the process, but not the lead in actually implementing it, which has been the case. Up to now, most of these tariffs include penalties that would be assessed by the RTOs as opposed to by FERC.

MS. SHEFFRIN: I would agree with my colleagues. Our greatest value is in prospective work that we do. It's always easier to avoid something than to deal with the after effects. But, at the same time --

CHAIRMAN WOOD: It's been the story of my life with your state.

(Laughter.)

CHAIRMAN WOOD: I'd a lot rather fix it.

MS. SHEFFRIN: We'd rather fix it. But, at the same time, enforcement is really critical because I think when the rule is clear, they understand that. It's transparent. They know what to do to avoid those enforcement actions. So I think having clearly laid out enforcement rules is critical to a well-functioning market.

CHAIRMAN WOOD: Does DMA do that now? Is there a separate person that says here's a rule and you broke it?

MS. SHEFFRIN: No. Right now, enforcement is done by the Commission. We refer actions to you. You're the one who is the enforcing agency.

CHAIRMAN WOOD: We've kind of -- big picture stuff and traffic tickets. I don't know if there's a separate answer in the Cal ISO for those two categories.

MR. ETHIER: I guess I would say we have a fair amount of specific things in our tariff that start to look a lot like traffic tickets. There are clear guidelines and you shouldn't go outside these and, if you do, you could be penalized or mitigated or whatever it is. A lot of that stuff that we use in New England is currently enshrined in the tariff.

CHAIRMAN WOOD: And someone in the ISO writes a traffic ticket?

MR. ETHIER: Most of that responsibility falls in my group.

CHAIRMAN WOOD: Okay. We're all discussing these issues as we speak and it's helpful to talk to the folks on the front line on that and many other matters. Thank you all very much for coming to visit today. We appreciate.

We'll stand and stretch for about five minutes and give David some breathing room.

(Recess.)

CHAIRMAN WOOD: Go back on the record and actually do our consent agenda now.

Madame Secretary?

SECRETARY SALAS: Mr. Chairman and Commissioners, the following are the items that have been struck from the agenda since the issuance of the sunshine notice on April 28th, E5, E6, E22, E36, E37, E51, G1, H1, and C5.

Your consent agenda for today is as follows: electric items, E8, 9, 10, 11, 12, 14, 17, 19, 20, 21, 23, 24, 25, 27, 29, 30, 31, 34, 38, 39, 40, 41, 42, 43, 44, 45, 48, 49, and 50; gas items, G2, 5, 6, 7, 9, 10, 11, 12, 13, 14, and 15; hydro items, H2, 3, and 5; certificates, C1, 2, 3, 4, 6, 7, 8, and 9.

The specific votes for some of these items are as follows: E43, Commissioner Kelly dissenting in part with a separate statement. E49, Commissioner Kelly dissenting in part with a separate statement. G12, Commissioner Brownell concurring with a separate statement; H2, Chairman Wood and C1, Commissioner Brownell dissenting with a separate statement.

I will note for the record that, as required by law, Commission Kelly is recused from the following cases on the consent agenda: E31, G5 and H2. Commissioner Brownell goes first this morning.

COMMISSIONER BROWNELL: Aye, noting my dissent on

C1 and concurrence on G12.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER BROWNELL: Aye, noting my dissents in E43 and E49 and being recused from E31, G5 and H2, otherwise vote aye.

CHAIRMAN WOOD: Aye, with the notation the Secretary noted.

Okay. A4, Salas?

SECRETARY SALAS: Yes, sir?

CHAIRMAN WOOD: We have here our long-awaited report on natural gas electric price indices to discuss what the survey showed and make some suggestions about what we might want to consider for our next step. I'll turn it over to Mr. Harvey.

MR. HARVEY: Mr. Chairman and Commissioners, good afternoon. Last July, in the Commission's policy statement on natural gas and electricity price indices, Staff were instructed to report any progress in the development of confidence in energy price indices subsequent to the Winter.

In addition, Staff was to assess criteria for use of indices in Commission tariffs. The report we're releasing today addresses both of those tasks.

The successful conclusion of the natural gas and electricity price indices will require confidence in price indices reaching adequate levels. "Confidence" is a word about perception; "adequate" is an assessment, even when informed by good information, but it is inherently subjective.

I cannot report to you today, the total success of the policy statement. The policy statement and its safe harbor were designed to attract more reporting and the results from Staff's recent survey covering this past Winter, indicated that only about a fifth of companies are reporting all of their reportable day-ahead and bid week natural gas transaction volumes, and about a tenth of companies are reporting all of their day-ahead electricity transactions.

While still well short of ideal, index providers have shown material increases in levels of reporting from their lows in late 2002, and more reporting may be coming. Recently, nine companies formally notified the Commission that they have begun reporting and 30 respondents to the recent survey stated that they planned to begin or increase reporting in the future, 16 of those in the next three months.

Those 30 represent about 20 percent of all of those responding to the survey. Every bit as important, survey results show that quality improvements are being made in price reporting processes.

The portion of companies that report to index developers through a department independent from trading, has doubled over the past year to nearly two-thirds. There has been an even more notable rise in the percentage of companies that conduct annual independent audits of their price reporting practices, rising from five percent to 58 percent over the same period.

The number of companies with a public code of conduct for buying and selling natural gas and electricity, as well as reporting transactions to index developers has risen from 36 percent to 65 percent. Each of these areas were specified in the Commission's policy statement.

As I said before, in the end, confidence remains the final criteria for success. We're asked in the survey about confidence on the scale of one to ten, ten being absolute confidence, and the average response was a seven.

I'm not entirely sure how to interpret that number. We've chosen to characterize it in the report as confidence in the price index report could be stronger. Obviously, it could be much weaker, as well.

In our assessment of progress, Staff held technical conferences, workshops, accepted filings, and issued two voluntary surveys. Most of these efforts have been deliberately designed to be as open, inclusive, and publicly accessible as possible, consistent with building confidence in the process.

In order to gain more detailed information about related activities, we did perform a recent survey with greater protections of confidentiality, in order to encourage participation.

I'd like to spend a few minutes reviewing some of the most interesting results of the survey with you today, if I could have the slides.

(Slide.)

MR. HARVEY: Survey respondents represented a diverse cross section of the industry, as you can see in Slide 1. Respondents could identify more than one business line, so this figure shows both the distribution of all the identifications, by company respondents, and how many of each kind was made only by a single choice.

For example, on the left-hand bar, 39 companies only identified themselves as marketers, while 54 companies identified themselves as marketers and at least one other kind of business line.

(Slide.)

MR. HARVEY: Going to Slide 2, reliance on indices varied significantly among companies as well. Respondents were asked to indicate how much of the natural gas and electricity they sold or purchased in contracts with pricing based on indices. These answers were within set ranges.

In the second figure, we've broken down the responses by business identification to give a sense of how different parts of the industry use indices in their contracting.

In effect, the average respondent indicated a range of use of natural gas indices from about 50 percent to about 70 percent of their purchases and sales. Electricity use was lower, in the range of about five percent to about 30 percent.

Given the way we calculated this, we really don't know where in the range the average is, but it is pretty unlikely that that answer falls outside of that range.

Most interesting here is the strong difference between behaviors. Gas indices are clearly far more important that electric. In part, this may be because the RTO markets effectively fulfill this role in many parts of the United States today.

In many other parts, spot markets may not be active. An interesting result here is that industrial customers are, by far, the most dependent on indices in their contracting. Producers come in second, with gas utilities close behind.

Marketers, electric utilities, and generators have less dependence, although, most likely, still more than 50 percent for their gas purchasing.

(Slide.)

MR. HARVEY: Going to Slide 3, we also developed ranges for reporting by market and by business line. In general, ranges were somewhat lower than I had expected, based on anecdotal evidence. Somewhere between 49 and 59 percent of relevant day-ahead natural gas transactions were reported on a volume-weighted average basis by respondents.

Ranges for bid week or month-ahead natural gas were lower, as we expected, at somewhere between 35 percent and 44 percent, and electric reporting was even lower, between 21 percent and 39 percent.

Once again, different kinds of companies had different kinds of answers, with respondents indicating that they were producers and said that they reported day-ahead gas 69 percent to 80 percent of the time, and bid-week gas, 73 to 83 percent of the time, the highest ranges.

I'll note that producers are much more likely to report all of their transactions, as many as 50 percent of them, for the bid week market. Industrial customers also showed fairly strong reporting. Interestingly, the lowest range for day-ahead reporting was from marketers, with 48 to 59 percent reporting.

Electricity looked different, with very low reporting rates for many of the sectors, but the lowest was from industrial customers, and the highest ranges from marketers and others.

(Slide.)

MR. HARVEY: Going to the last slide, then, finally, as I reported previously, we tallied respondent assessments of confidence on a one to ten scale.

(Slide.)

MR. HARVEY: The results in Slide 4 show the distribution. Few gave indices either perfect scores, or the worst of the scores, only about one percent giving them one's or two's or ten's. Most responses were eight, with enough of a preponderance below that that the average was very close to seven.

Industrial customers and gas utilities were slightly higher, on average, and marketers were slightly lower. In fact, we did notice a slight tendency for those who are more dependent on indices, to have more confidence in them overall.

COMMISSIONER BROWNELL: Would you say that again?

MR. HARVEY: Those who reported being more dependent, using indices more in their contracting, tended to have slightly higher confidence.

COMMISSIONER BROWNELL: It tells you something.

MR. HARVEY: Yes. To encourage more informed discussion of these issues, we have added to the back of the report, an extensive technical appendix to the report, which breaks down responses to all the questions, as much as possible, without violating the requests for confidentiality.

We hope to see further filings in the docket, based on participant analysis of this data, basically a back-and-forth analytic dialogue, in fact, on as much information about this as possible.

Further improvements in natural gas and electricity price discovery processes are clearly possible. What is less clear is whether the benefits from further improvements would exceed their costs.

We've identified four options for future Commission involvement in price formation. The first, the Commission could end active involvement with price formation issues and permit the industry to address issues without any formal structure of further guidance from the Commission.

Second, the Commission could actively encourage the industry to implement the policy statement fully and monitor closely, the level of trading activity reported by price index developers, as well as compliance with the policy statement standards for reporting and index development.

Third, the Commission could move towards some form of mandatory price reporting of energy trade data, as a number of parties have urged over the past several months. Fourth, the Commission could attempt to encourage greater reliance on platforms for trading, confirmation, settlement, and clearing.

Some parties have observed that the most open forum for obtaining accurate price information is trading on electronic platform. In addition to electronic platforms for trading platforms set up to facilitate confirmations, settlements, and clearing have the potential to further aggregate transactions for the purpose of forming more robust price indices at low incremental costs.

Each of these options has strengths and weaknesses. We believe it's best explored in another public direction with market participants reacting to this report.

Before concluding, I would like to turn it over for a few minutes to Ted Gerarden to talk about our specific recommendations with regard to using indices and tariffs.

MR. GERARDEN: The policy statement requires that, prospectively, indices used in jurisdictional tariffs must comply with the standards of the policy statement and reflect adequate liquidity at the referenced points.

Shortly after issuance of the policy statement, the Commission issued orders concerning specific tariff filings, and in those cases, instructed Staff to file a report on the changes in indices in those tariffs, so, part of the report we're providing today, addresses these tariff issues.

We held a public workshop in November of 2003 to gain a better understanding of the uses of indices in tariffs and the importance of the liquidity at trading locations. Indices are used in natural gas tariffs, primarily for a periodic cashing-out of imbalances, but also calculating some penalties and settling discounted transportation rights.

Use of indices in electricity tariffs is somewhat less common, but electricity indices are used to cap the price for affiliate transactions under market-based rate authority, and for financial settlement of imbalances or losses.

In all of these cases, indices are integral parts of the tariffs and facilitate jurisdictional transactions, but our recommendations with respect to indices used in tariffs are for these tariff purposes and they do not relate to the suitability of indices for broader commercial purposes.

To determine whether price index developers are meeting the expectations of the policy statement, we've invited price index developers to file statements regarding their adoption of policy statement standards.

Ten responded. Of those ten, we recommend that six be designated as in substantial compliance with the policy statement: Argus Media, Energy Intelligence Group, Intercontinental Exchange, IO Energy Intelligence Press, and Platt's.

We also recommend that three others, Bloomberg, Btu/DTN, and Dow Jones be deemed conditionally in substantial compliance, pending further statements on specific points that are identified in the report. The tenth filer, by the way, Reuters, was not evaluated because Reuters stated that it does not publish indices for price formation purposes.

We recommend one important caveat, however, on index developers meeting the policy statement standards: Several index developers qualified their willingness to provide the Commission with access to confidential price data in the event of an investigation of possible false reporting or manipulation of prices.

Staff recommends that the Commission requires a condition for the use of their indices in jurisdictional tariffs, that index developers affirm that the Commission will, upon appropriate request, have access to relevant data in such an investigation.

Turning to the second aspect of the requirement of the policy statement, the issue of adequate liquidity at specific locations, some index developers have added some quantitative measures to monthly and daily indices over the last several months.

The measures vary from publisher to publisher, and from index to index. Some are different from daily indices versus weekly, some provide volumes, and a few provide number of transactions. Some designate volumes and transactions by tiers.

One recurring them in the comments, however, and in the narrative responses to the survey that we had heard from the market participants, is that they would like more information and more uniform information about the activity underlying calculated indices at each trading location.

To this end, we recommend that the Commission require that as of September 1, 2004, any index used in jurisdictional tariffs must regularly provide the volumes and the number of transactions from which the index value at each location is calculated.

If there were no transactions but a price assessment or estimate is published, the index must so state. This information will permit market participants to gauge the depth of thinness of trading at specific locations.

We also recommend that the Commission adopt minimum levels of activity at any index location used in a jurisdictional tariff, measured by volumes or number of transactions at the relevant location or locations.

The recommended minimum volume levels are 25,000 MmBtu per day for natural gas, or 4,000 megawatt hours per day for electricity. And the minimum transaction levels are five trades for daily index, eight trades for weekly index, or ten trades for monthly index.

The evaluation of whether activity meets these recommended minimums should be done over an historical period. Because many index developers do not provide volume and number of transactions in indices used in tariffs, we recommend that the Commission permit existing indices to be used until there is such a period available to evaluate, so long as the indices are providing the minimum necessary data by September 1st.

Finally, we recommend that action on pending tariff filings be deferred so that the Commission can take comments on Staff's recommendations. As Steve mentioned, we urge the Commission to hold a public conference on all issues related to price indices, including the criteria recommended in the Staff report. Thank you.

MR. HARVEY: That concludes our presentation.

CHAIRMAN WOOD: I think our plan, based on our schedules, is to have such a conference on June 25th. That would look at not only our responses to this, but the broader issue of liquidity in the marketplace. As Steve pointed out, we do look forward to that. Thoughts, comments, questions?

COMMISSIONER BROWNELL: Steve, you talked about the market making some determination on whether further work and refinement was cost-effective. Tell me where that came from?

Is that what we're hearing from the industry, that, at some point, all these refinements and requirements are costing more than they put value on?

MR. HARVEY: I think it relates, again, to this notion of confidence, which is a hard to put your arms around kind of thing. There is sort of a wide distribution, as we saw on the sort of one to ten confidence scale.

There are many who think that things are working fine at this point. There are some who believe that they are not. That shape is sort of at the low end and blunt at the higher end, is roughly the shape you would expect, even sort of at best.

You would want to see it a little farther over, but really, the question ultimately is, is there enough confidence, sort of across the board, given that kind of a distribution, that you can say, you know, we've done enough, and it's time to move on.

Staff doesn't feel in a position to make such a judgment, and certainly with regard to tariffs and all, you are in a position at some point to make such a judgment. With regard to contracting, the industry is going to be in a position to make that judgment.

That's why we think it's important to get feedback in attempt to concretely lay out that confidence issue as much as possible in this document, get some good feedback through this process, and see if what comes back is that maybe we need to stop this, or we need to drive forward and do more.

COMMISSIONER BROWNELL: Isn't the ultimate test of confidence, whether people use it or not?

MR. HARVEY: Yes.

COMMISSIONER BROWNELL: Isn't one of the indicators perhaps the development of these other sources like platforms, and have we not seen volumes increase on the platforms. In the isolation of this kind of information, you're seeing some market activity that reflects kind of choices that people are making.

MR. HARVEY: Yes, and I think that is sort of the market working itself out, creating choices for information about prices, and then those choices becoming stronger or weaker over time, based on the technology people use, based on the way they interact, based on what they have confidence in and what they don't.

It's one of the reasons our recommendations for use in tariffs point to sort of more information about levels of activity, so that people can make those judgments in a very informed way.

COMMISSIONER BROWNELL: I guess some of them must believe they're informed today. How did you arrive in these recommendations at some of these minimums? Was that recommendations in the survey or from the industry?

MR. HARVEY: We did have a meeting with the industry to kind of discuss what the appropriate levels would be. There is very little, if anything, in sort of the economic literature that would point to a right answer or what the right threshold is for these kinds of markets.

And so, in many ways, this was our assessment, based on those conversations, based on how the tier system has worked with some of the publishers and sort of where they were making sort of cutoffs between levels and tiers of what they were reporting, and then how people were using that.

But there's not a science to it. There isn't anything that says this is exactly the right kind of threshold, and so we kind of picked what seemed to be in the culture, the most sensible thing.

COMMISSIONER BROWNELL: So the idea is to get comments about whether these are the right threshold, and somehow equate that -- I'll be confident if I see X-number of trades.

MR. HARVEY: There are sort of two goals, I guess, embedded in one document here. One is the sort of general confidence within the markets, which is, of course, very important to the Commission, because those are the markets providing rates that ultimately need to be just and reasonable, competitive, and that sort of thing.

There's a more specific set of concerns which really relate to primarily these tariff references for balancing, which say, are these formed in a way that works well enough for us to be confident in plugging them into a tariff and not worrying about it.

Those are very different criteria. Those are one of things that we try to be careful about in here. People choosing about how to contract, based on their interpretation of things, should be different than necessarily the Commission's considerations about how to plug it into a specific tariff, working in a particular way in a particular calculation.

We have to kind of speak to both of those there. The thresholds are with regard to the tariff issue. People may or may not contract based on that, dependent on their own understanding of a particular location, and we indicated that that was the right way to think about it in here.

COMMISSIONER BROWNELL: Have we had any complaints about the current state of affairs for the use of these in tariffs? Has somebody come in and said, I'm forced to rely on indices that I don't have confidence in?

MR. HARVEY: I don't believe so.

MR. GERARDEN: Part of the reason for that may be that what we heard at the conference in November from the industry was that the tariff facilitating devices, price, and cashouts, was useful for the industry, and there was not a great deal of concern over the adequacy of liquidity at a point, because everyone was comfortable that they were getting a reasonable price for purposes of cashing out imbalances.

It was preventing the kinds of maneuvering that some companies might do if they had some opportunities to arbitrage prices. So, for that level of use in the tariff, we took that into account in coming up with the volume levels or the suggested criteria that would make a number of points available.

When we looked, for instance, at the specific cases in which the Commission had issued a requirement for the Staff to provide a report, the tariff points that the companies had filed in those cases generally met or exceeded all the criteria that we proposed, so that would facilitate the limited uses in tariffs of cashouts, imbalances, penalties and similar uses.

COMMISSIONER BROWNELL: Thank you.

COMMISSIONER KELLIHER: I had a question about how price indices are developed and used in other industries. Price indices are not unique to the energy industry. I'm just curious, how are they used in other industries? Is mandatory reporting common in other industries?

MR. HARVEY: They're used in very different ways in very different industries. They have been used for a long time in many different industries -- coal, some other energies, some metals.

COMMISSIONER KELLIHER: They are in the securities industries?

MR. HARVEY: Right. In general, I would say that there probably hasn't been as much scrutiny of the way they operate as we have applied to these indices, natural gas and electricity. I don't know that for a fact in every particular case, but, in general, I think we spend more time looking at them now than most of those have.

I will say that I don't know that they are as central to the operations of the market in all of those industries as they are here, as well. It's again, sort of the shape of the way this industry has used them, and created them, that's very sort of distinctive.

MR. PERLMAN: I can add to that. In the oil industry, there's a similar reporting structure where the index was a product of information provided to the publishers. We looked at one of our conferences at a model for minibonds. That was effectively an SRO type of process where they had come together, and all the dealers in minibonds agreed to provide information to a single clearinghouse that was made available to publishers, because there wasn't enough liquidity in those markets for it to be picked up in the general exchanges. They were all over-the-counter type trades.

A lot of these other types of indices are utilized as components of derivatives, so other indices use them for derivatives. Interest rate swaps are a big component, currency swaps, things like that.

Most of those have very transparent sets of data that they can use, further indices often published by publishers, or a product of exchange trades. You referred to that, I think, in one of your questions.

Some of these indices are products of exchanges where equities are traded or other types of securities are traded, that can then be used in derivatives.

COMMISSIONER KELLIHER: Is it common or uncommon for some economic regulatory body to set minimum requirements and adopt -- are the recommendations you're proposing, common to the use of these indices in other industries or is it uncommon?

MR. GERARDEN: A factor here is that these are proposed in the context of the indices being used in jurisdictional tariffs. You won't find that same structure very commonly in other industries and that's part of what Steve is referring to as the two different purposes of the report, the broader purpose being to look at the confidence the industry has in indices for commercial purposes where billions of transactions take place.

At the same time, we're also looking at instances in which indices are used in jurisdictional tariffs, and the Commission is concerned that the indices there represent accurate prices, and that they provide comfort that a transaction that's under a jurisdictional tariff is being done at the correct price.

MR. PERLMAN: I think one thing you ought to think about in that context is the other indices that are made available to market participants, are either chosen by them or not used by them at their discretion in their arrangements.

Here, any shipper in the electric world that is clearing through the Commission-regulated world, is obligated, in effect, to be subject to these indices.

As a result of that, the Commission must find that as a component of that tariff, his tariff component is just and reasonable for that purpose. You can use the approach we've talked about to reach that conclusion or another analytical approach, but the Commission has to address that as a component of the overall tariff structure, and that does make it different than other industries.

COMMISSIONER KELLIHER: Thank you.

MR. MARTINEZ: May I add to that, that there's a relation between how transparent the market can be and the structure that the market takes. In this case, we're dealing a lot with bilateral trades.

In the case of financial markets, many of the trades are taking place in multilateral settings. You have basically auctions like in bonds, bond auctions held by, say, the Treasury Department, or you have, like, the exchanges in the financial markets or Comex or the other commodity markets like NYMEX.

You have everybody trading at the same time. In the case of bilateral markets, to give an example of the other extreme, in a very non-transparent market that is not "commoditized," it would be the housing market, for example. When one goes to buy a house, generally it's -- just recently, a professor, I think at Yale University, Robert Schuler, wrote a very influential book about this and how to calculate housing price indices.

In that case, what happens is that most transactions are recorded. They have to be reported to some agency. When one goes and buys a house here in Washington, D.C., usually, somebody is going to lend you for a mortgage, and then goes and looks for comparables. There is no index published for housing, but most of the time they look for comparables and they go to public records and they can obtain that information.

There is one case in which there is not really an index that is widely available, but there's a 100-percent reporting requirement, so there are cases, depending on what the transaction is, that is one thing that can be achieved, and that depends on the technology of information-sharing.

One differs on the structures of markets, auctions, or bilaterals, or they can have 100 percent reporting requirement. This is something that we would like to investigate and get back to you.

COMMISSIONER KELLIHER: Thank you very much.

COMMISSIONER KELLY: Regarding electric price indices, would clearing within an ISO context provide us with more information than we're currently getting or would it just duplicate the information?

MR. HARVEY: In the RTO context, it would duplicate the information. Clearing, in general, in areas that are not RTOs would give you more, but it really wouldn't add anything with an RTO.

COMMISSIONER KELLY: Thanks.

CHAIRMAN WOOD: The first chart, survey respondent's reports using -- you have industrial customers. Let me just ask what this chart is telling me. It says "prices and sales at index percent of all industrial customers, 68 to 89 percent." What does that mean?

MR. HARVEY: When people responded to our survey, one of the questions was, what percentage of your purchases or sales of gas or electricity are based on index or priced with reference to an index point and there only ranges are like five or six ranges that they could have picked. Rather than making assumptions on where things go on range, and doing the volume weighed average, based on that, we did sort of one end of the range versus the other end of the range, so we created that range. What that says is, for industrial customers for gas, somewhere between 68 percent and close to 90 percent of their purchases of the average industrial customer responding to this survey -- let me throw an caveat in there a come back to it a little bit on interpretations here, we would tend to buy within that range based on index rather than going out and saying, as an industrial customers, I'll do this deal at this price with you. The strong tendency of respondents was I'll do a deal with you with reference to the index price.

CHAIRMAN WOOD: So the same thing would hold true for gas utilities in these other categories?

MR. HARVEY: Right.

CHAIRMAN WOOD: I know we didn't ask this specific question because it was beyond what we were talking about. We kind of talk about the formation of the survey instrument trying to get a concept of what percent of the total universe are deals that are at a fixed price as opposed to just hooking it back off of the floating price here.

MR. HARVEY: There may be some ways of making rough estimates of that, but we haven't move terribly far down that path. There was one filing on Friday from the Imprac Group, a group of industry and publishers. And there's a section within the paper that discusses their filing because they came up with ranges higher than ours, uniformly, cross the board. That, we think, has to do with a different methodology and a different source of information, not anything of concern, which is one of the reasons we're excited about getting out as much data in the back of this paper as possible so that we can all refine kind of our views of this stuff.

They did attempt to make some estimates of sort of the size. One of the tricky things about the natural gas industry, in particular, is because it is so much based on bilateral deals and there isn't any real central repository of information about it, it's very, very hard to know how to separate out the pieces of the industry. It's not a transparent industry in that sense at all, which is unending frustration to us whom you've hired to be market monitors. In that case, I'll say, because of that, it's hard to figure out how much of the market is based on monthly indices, how much is based on daily indices, how much is forming the one versus the other.

We do plan on continuing to try to do some analysis to get some rough numbers of that because one of the concerns that we have is you may have fair amount of reporting from a fairly small component of the overall industry setting the price for a lot of it. That can be okay, but getting a sense of what those ratios are could be important in terms of developing confidence in those prices, too.

CHAIRMAN WOOD: That would be my big concern.

The reason why this has been an issue for me for over a year is what we found when we first came in here is on the other side of the agenda in the electric market. We had a state that we just visited with Anjali from that did this horrible thing that everybody looks back now and says it's the most stupid, dumb thing you could ever do and have everything be hedged off the spot price. But, you know, when I see a pretty thin slice here that is really the fixed prices that we agree that for the next X years, we're going to buy and sell this commodity at this price, which is what we encouraged people to do in the electricity markets because we need to know the time they get fixed at the front end of the contract. But we've got here an industry that for a product that's gone from $2 to $6 in the last three years is pulling a whole lot of traffic along with it as opposed to just the 5 percent residual that we are now accustomed to in the California market being set by the spot price. That's why we care because it is setting a tremendous amount of commercial value in the energy marketplace in a way that we're very familiar with and had a bad experience with. So that's why I care.

I'm pleased with the responses, I think, that the confidence is kind of a gentleman's C. I do like what we found out in the last year that some are better than others. Clearly, we can see from here the electronic mini-to-mini exchanges, get the A. The other price developers range from kind of B+ down to D, depending on how that gets done.

I do, actually, look forward to try to understand what it is, other than kind of customization of buys and sells, which is a big issue in this industry. You can't just buy a standard lot like you would shares of stock. It's a lot more custom-fitting here. But I understand a lot of people aren't using electronic exchanges. That seems to be how most of the commodities -- I think Joe's question drew out some examples, but it seems to me that the comfort that most people have with something like that has certainly addressed a lot of my issues. I see how those have played out over the past couple of years. Those are clearly -- at least the issues we care about, I'd be curious to know if it solves issues the market cares about?

As to the other half of what you all talked about and what Ted spoke to, I think the jurisdictional tariff issues -- I've very supportive, barring better comments to the contrary of the two recommendations that you all made that are applicable to everybody about the broader disclosure on volumes that are used to fix the price that's reported and also the ability that we've talked about, and had issues with, over the past two years about our access under properly controlled protocols to the data for specific investigations. I think that's not an unreasonable condition to place -- but, basically, I gather with the tariff you got a lot of value for your product. There's a quid pro quo there and we've got our job in policing the marketplace in exchange for getting kind of a good housekeeping seal of approval. You pay at the door. I don't think that's unreasonable.

The question I asked about the volumes and where you got those from, can you just kind of reiterate because I'm not sure I heard exactly where those numbers came from, the volumes that were used to set, on the liquidity side.

MR. HARVEY: Okay. Like I said, there isn't sox of a right answer in the sense of I can build up a set of equations --

CHAIRMAN WOOD: Let me just ask you the punch line. How would this play against what we're seeing today? Do you have any idea? Does this largely validate what we saw today or cut off some of the lower stuff?

MR. HARVEY: We tend to cut off the lower stuff. It's a little different because we're adding a couple of requirements that aren't quite here today in terms of some stuff we'd like to know. But, in general, when we've looked at it, the majority of what would be considered sort of tier I and I believe much of what would be sort of considered tier 2 in sort of typical parlance today, would actually fall within this category.

MR. GERARDEN: It is not a very exclusive category. It will bring in a number of trading points. It would leave out points at which, antidotally, we hear from the industry that they don't have much confidence in the price that's reported anyhow. Some of the indices indicate, in their filings with us, that they were providing estimated assessments of prices because they didn't have enough activity to calculate an index prices. To the extent to which that's made clear by the indices, varies a little bit from one to another. But it appears that a number of the points that we would exclude by the minimum criteria that we're proposing are points as which there's little trading and not a whole lot of reason to be confident.

CHAIRMAN WOOD: Rafael?

MR. MARTINEZ: Some of the numbers -- the reason why you see us hesitate has to do with calculating those numbers and how many trading points would satisfy this condition. The difficult is precisely at the heart of the point of lack of transparency. We don't have that much information to evaluation, so I can tell you, for example, that one of the 4000 megawatts in electricity -- megawatt hours that comes from some of the information we do see comes from ICE.

In our MMC, we have it on, on the screen. The typical transaction is 50 megawatts times 16 hours of peak time. That's 800 megawatt hours that we imagine and this is from conversations we've had. And the non-scientific part is that five transactions reported is something we'd be comfortable with. Then 800 times 5 is 4000. That's five reports of transaction, which, in some publications, that would be double counting. That means as least three transactions behind that. So it's not a very strong criterion, but we've derived criteria that way. For example, we have the 25,000 in MmBtus per day for day-ahead gas. That's one of the criteria used by Platts and NGI for tier 2. That's also a typical size over the transaction that we see in our records from ICE. So it's been made from patches of information.

Precisely, because lack of transparency also effects the regulator who is one of the consumers of information as well, so it would be a little difficult to split the chicken or the egg. We're trying to increase transparency using criteria that are generated without sufficient transparency.

MR. GERARDEN: Which is probable the reason we recommend this be the subject of comment from the field before the Commission acts on it.

(Laughter.)

CHAIRMAN WOOD: When do we want to do that, by the way? Do we want to have written comment in advance?

MR. HARVEY: We've encouraged that all along.

CHAIRMAN WOOD: Do you want to put this out today and then give us your comments, Harvey, in preparation for the 25th, I think. We are giving a fair amount of information about coming out beyond what we talked about today and it would be very helpful, I think, if people could look that over and bring points of view back, based on some of these facts.

MR. GERARDEN: We can come up with a proposal of some dates for filing.

CHAIRMAN WOOD: Two weeks before that conference. We can massage the data and talk about it.

COMMISSIONER KELLY: Steve, did we probe, in the questionnaire, why people who had confidence in the indices had confidence?

MR. HARVEY: I don't believe we explicitly asked a question like that. We encouraged in the first survey -- the people I think found frustrating because it was a little less structured that way for as many comments as possible. I don't believe we got nearly as many the second time because we were really trying to build as much of a volume metric and quantitative view of the world as possible.

MR. GERARDEN: In fact, there were many narratives provided along with the survey responses and we encouraged parties on any question to provide a narrative.

That is not the same thing as asking all of them please comment on this. But there is some information that we could glean from the narrative responses.

MR. PERLMAN: An example of that would be one of the participants at our liquidity conference told us that, as traders, we're very active in the market. All trades allow is all locations. They knew the price and the next day they were at point in time and they were seeing an index and they knew the index was inconsistent with the actual trades that they were undertaking. And, as time passed by, those complaints had stopped and he was seeing a real convergence between the trades were taking place on the day for which the index was being reported and that level of objective information as well as their internal reformation of their process, consistent with the CCRO white paper type approaches to reporting, where it's sort of overall providing a level of confidence to at least that company.

MR. HARVEY: I should say, because we've also spoken to a lot of people and have created lots of venues to do that, we've had these filings. Two things to just highlight real quickly, again, I think, are not completely uniform, there is always somebody who has a different opinion. There is always a percent or 2 at the far end of the graph, but one is that the process is far better today than it was a year and a half ago. There's just absolute consensus on that and I think that's very important. And, in many cases, people have credited the Commmission's attention for helping to do that. I think those are both kind of important feedback that we've picked up along the line.

COMMISSIONER KELLY: Thanks.

COMMISSIONER BROWNELL: Actually, adding to her question, did we every ask, or do we know that there was a decline in people using the indices as this information came out? Did we see any measurable drop off?

MR. HARVEY: In the use of them? This last survey is the first time we've actually tried to quantify to what degree they're used. But I would say, no. The concerns that were expressed, generally, were from folks who said I don't feel like I have a choice but to use indices and so I feel stuck. So I don't remember any of those concerns being expressed, so I'm going to do something else at this point.

MR. PERLMAN: One other comment about something the Chairman had mentioned earlier about these results and looking like some of the entities were subject to the volatility and the price takers of the index. One thing we were also told was some of these entities, particularly, the LDCs, enter into these arrangements for security of supply and then they hedge with derivatives. They'll hedge with

Henry Hub futures or things like that. So there's a certain amount bases to fix the price and get a secure supply. Pay an index price, but have a level of price certainty, based upon other means. We can explore that our conference as well.

CHAIRMAN WOOD: That's helpful, particularly, as we're talking to the state commissions about the importance of allowing for hedging. That, combined with the index priced product, does start to look like our normal handshake deal for a fixed price.

MR. HARVEY: There may actually be within the survey, at the next level of analysis, be some ability to pull that out. One of the questions we did ask was, and can correlate back to these results to some degree -- I haven't tried to look at it yet, was how actively engaged these responding companies were in financial trading as well. It doesn't mean it was necessarily hedging versus speculating, but we can probably get some viewpoint into that based on the information we collect.

MR. MARTINEZ: Some of that information is in the tables that were presented. Trying to be transparent ourselves, some of the information we put out in the appendix, we've not fully analyzed, but you had asked before the extent to which indices and we do have one question that addressed that and I can tell you that at least 68 percent of the respondents said that they evaluate the index at more than half the volume they trade in natural gas. In electricity, it's on 6 percent of the volumes traded. Only 60 percent of respondents said that they used indices for more than half their volume.

MR. HARVEY: I didn't complete my caveat from earlier. This was a survey. It was designed as a voluntary instrument. The responses in it were voluntary. We are under clear instructions from OMB that lots of statistical analysis here is not appropriate. These are really a tally of what the respondents said. One of the things that interesting about looking at the respondents is that there was a lot of diversity. There's a lot of diversity in this industry in terms of strategy, in terms of behavior that's actually a good competitive thing. But what that means is it's hard to sometimes generalize. We ought to be careful about generalizing the results that in here too far. This really has to be understood in the context it is not a statistical study. It can't be a statistical study. You could not build a statistically significant resource here.

CHAIRMAN WOOD: Did you get a sense -- you mentioned in the opening comments about a fifth of the people, 30 parties had identified that they would comply with the policy statement in the future and beginning reporting in compliance with that and I wondered what conditions do they want that we haven't put out as of a year ago?

MR. HARVEY: Let me get sort of the numbers so that we kind of understand this.

CHAIRMAN WOOD: All right.

MR. HARVEY: In the behavioral rules, the requirement to tell us whether someone was complying, whether it was reporting in full compliance or not, for gas we received about 250 responses, for electricity about 580 responses, about 4 percent of the electric and 20 percent of the gas respondents said they were reporting in full compliance.

Now there are number of reasons why you might not be able to say yes to that. One of them is you don't do the kind of transactions that turn on the prices and probably quite a few of these companies don't. They just buy based on index and that alone. The other is probably the requirement that seems to be most difficult, I think, given current sets of systems is the completeness requirement.

In effect, you can't pick and choose where you're going to report. This is particularly important in many ways if what we're understanding about this sort of diversity of the way people is true out there, there's some evidence, particularly, in comparison with Imprac numbers that says the more liquid markets are reported more than the less liquid markets. That's not necessarily surprising when you think about it. Nothing succeeds like success and it's the less successful places that I think are of big concern to us, particularly, in the tariff issues.

There's a couple of levels of reasons why somebody might not, running all the way down to we're just not interested in doing it. There's too much concern, too much risk out there. We have certainly talked to companies -- I've certainly talked to people from companies who have said this looks risky. You guys have investigations. The CFTC has investigations and this is just too dangerous and we're not going to do it.

I believe AEP announced concerns about that even yesterday. And so there's a variety of responses. It's the ones who are basically saying we're not going to put the processes in place and we're not going to do this that concern us because we'd certainly like to have that contribution of information.

MR. GERARDEN: In respect to the 30 companies that you mentioned, a number of them either also filed comments and were discussed in the report or provided some narrative information in their survey responses. In many cases, it's a matter of them putting into place new software and having some internal controls that they're developing, having it reviewed by either an internal audit group or having an outside auditor look at their processes, testing them. And many of these companies are taking the policy statement standard very seriously and doing a very workmanlike job of laying the ground work to make sure that they've got processes in place that meet all the requirements of the policy statement. Some of them say it'll take two or three months. Some of them say even longer to finish that process, but underlying that I think there is some comfort they are doing a very serious job of it and some of them are some of the larger players. I think, overall, we say that small companies tend to shy away from reporting because of the perceived burdens of complying with a policy statement.

More of the larger companies tend to be reporters than smaller companies and you'll see the data show up that more volumes are reported as a percent of all volumes than companies reporting as a percentage of all companies.

MR. HARVEY: I will say your guidelines have been out there close to a year now. We've clarified them a couple of times, based on request from the industry and there's always a few saying just give us a few months down the line to -- so there's a certain level of frustration in terms of that on our part as well.

CHAIRMAN WOOD: Is the data public as to who is and isn't?

MR. HARVEY: As to who is and isn't reporting that way?

MR. GERARDEN: The public source would be the notifications that were filed as a requirement of the market behavior rules and those are the numbers Steve is referring to. There are some companies that filed comments in response to our March 5th notice. That's public. The 30 companies that say that they plan to begin reporting are part of the survey responses. We've not yet released the names of those companies because we've been treating all the survey response data confidential.

COMMISSIONER KELLY: Is this report on our website?

MR. HARVEY: It should be at any time now.

MR. GERARDEN: If it isn't now, it will be shortly because -- made sure it was primed and ready to go. Both the reporting of the detailed technical appendices will be on there.

COMMISSIONER KELLY: I'm sure it will be quite valuable to the industry, too. Thanks.

COMMISSIONER BROWNELL: Maybe as part of our question, as we set up the technical conference, is to ask people if they would share what the actual cost to the company is to comply.

COMMISSIONER KELLIHER: Three quick ones.

(Laughter.)

COMMISSIONER KELLIHER: I know that's not what you want to hear, but it has do with trading hubs, transactions that occur trading hubs. Is that data available only through a price index developer? Is it otherwise available?

MR. HARVEY: Gas or electricity?

COMMISSIONER KELLIHER: Cinergy data. Do you only get that through a price index developer?

MR. HARVEY: Yes. Because those are fundamentally bilateral markets. There are different sort of flavors of price index developers. That's one of the things we talk about. One would be, in effect, the trade press polling. Another would be to the extent that that's traded in an online exchange. For example, ICE really is the example right now. ICE has for some time now been publishing that data in a sort of index form on a daily basis as well.

MR. PERLMAN; But there are RTO trading hubs that are available from the RTOs, so PJM West, the hub in NEPOOL and the various zones in New York. For example, sometimes in the RTO regions and ISO regions it's available outside of a price index developer.

MR. HARVEY: Right.

COMMISSIONER KELLIHER: The trading hubs that do exist, it's my understanding some are approved by the CFTC, but not all. Isn't there CFTC role in approving or permitting a trading hub to engage in transactions?

MR. HEDERMAN: If there is a futures contract that is transacted on the NYMEX and CFTC that's approved by contract.

COMMISSIONER KELLIHER: So the trading hub doesn't need CFTC's blessing to exist, but, if certain transactions occur, they need --

MR. PERLMAN: The trading hub is really a delivery point for a transaction. If you had a futures contract that had delivery point at, say, PJM West, then that whole contract would be approved by the CFTC to be traded on an exchange. You can do a lot of different types of transactions based upon that delivery point. It creates a fungible location so people can do forward trading without having the branding or specificity of specific delivery points and it creates a price hub.

COMMISSIONER KELLIHER: This is all leading up to a question about jurisdiction. There's not a problem if we're to pursue some of the recommendations you're pursuing. We're not looking at a conflict with CFTC and some requirements that they make?

MR. HARVEY: No. In fact, this process -- before you joined the Commission, this process involved several technical conferences that we held, actually, with CFTC staff actively involved as well. We've coordinated quite extensively in this process and when the policy statement that had the safe harbor was presented when the Commission voted on that last July that was timed to coincide with the press release by the CFTC that underscore sort of their commitment to good processes as well.

So we've been pretty careful to coordinate as much as possible. There are elements that are sort of different jurisdictional issues, but, in general, I think both of our interest have been well served by working with them.

COMMISSIONER KELLIHER: Thank you very much.

COMMISSIONER BROWNELL: Maybe we should invite them to the conference.

CHAIRMAN WOOD: We'll do that. All right. We'll print out the comments and talk again on July 25th. Thank you all for the hard work.

Fellows, next item on the discussion agenda is E3, PJM interconnection LLC in Docket EL03236, a presentation by David Perlman and David Kathan accompanied by Alice Fernandez and David Mead.

MR. PERLMAN: Good afternoon. I'd like to note at the outset you have three Daves and an Alice here. I'd like to also thank for working on this project Mike Coleman, Derrick Ginder and Mike Goldenberg, Bill Lictenstein, Kevin Hiller and Debbie Yacth.

What you have before you in Item E3 is really a general policy statement type component associated with an analytical approach to deal with issues that we have heretofore called the liability must run issues as well as a specific application of that type of policy to a real case controversy, the PJM matter, that we had dealt with originally in the context of a complaint by Reliant and PJM followed through with a filing thereafter.

MR. PERLMAN: We are paying for the process the Commission announced last year and held technical conference in February to address the reliability must run issue in a broad, comprehensive manner. Here the Commission finds that there is not single solution to these RMR issues, which no dub reliability compensation issues or, at least, we've created a new label for them. Rather, this draft announces an analytical framework in which reliability compensation issues would be considered. The framework is focused on the specific review of the type and magnitude of what we now call RCR problems in organized markets.

If the market does not exhibit a material or liability compensation issue, less invasive solutions should be employed for addressing the outstanding minor market issues that are there in this context. However, more importantly, if the market does exhibit material reliability compensation issues, such issues should be clearly identified and we would recommend market solutions be tailored to solving the issues and be employed to bring about the appropriate structural incentives for market-based solutions through the higher revenues received from the market for generators needed for such things as investment in load pockets.

Some of the market design elements that should considered include locational install capacity, locational reserves and, in addition, the avoidance of such things a socialized charges or uplift that would otherwise mute price signals. If market design approaches are not sufficient to solve problems, then other approaches such as RMR contracts for short-term type issues or ISO auctions may be employed, but only after the attempt to identify the issues and resolve them through market design.

With that, I'll turn it over to Dave Kathan who will talk specifically about the PJM case.

MR. KATHAN: In this order, the Commission considers PJM's proposed tariff provisions within the context of the general reliability compensation policy that David just presented and rules on the specific provisions in accordance with this policy. The order directs the following:

(Slide.)

First, the order defines that PJM's current offer capping rules work effectively to mitigate market power in a manner that is fair to most generating units. However, the order finds that the existing tariff provisions for offer capping are unjust and unreasonable for units that are cost capped, a significant portion of the run hours and are needed for reliability. The current tariff does not include a specific process for such units to obtain a higher bid cap or other means of ensuring reasonable opportunity for recovery of their costs.

To address this deficiency, the order directs PJM to revise its tariff to provide the right to -- mitigated units needed for reliability to receive higher offer caps for alternative compensation.

Second, to further support this policy, the Commission directs PJM to develop a clear policy on retirement. Third, the order accepts PJM's proposed suspension of mitigation when there is sufficient competition in a local area. This proposal appropriately addresses a key problem with the current mitigation approach while continuing to address local market power. However, the order finds that the proposed suspension of mitigation accords the market monitor excessive discretion in determining the degree of competitiveness and directs PJM to submit a compliance filing to provide additional justification for their competitiveness standard and submitted revised tariff language.

Fourth, the order finds that the record in this proceedings does not support a finding that the exemption of the post-1996 units from cost capping has been unjust and unreasonable. The order rejects PJM's proposed blanket removal of the proposed 1996 exemption because of the equity and regulatory uncertainty concerns.

The Commission will, instead, consider specific evidence presented by the market monitor or others that a specific generation unit possess market power on a case-by-case basis.

Fifth, in keeping with the general policy, the Commission believes RTO resource procurement, whether long-term contracts or a direct procurement of generation, could, in limited situations, be necessary to provide adequate incentives to generators and the financial community. To build new infrastructure and load pockets, the order rejects PJM's proposed local market auction proposal as it is currently designed.

PJM has not met its burden to justify its proposal as just and reasonable. Although the order rejects PJM's proposed auction, the Commission is still open to a last resort auction that would address long-term reliability problems in PJM.

Sixth, the Commission rejects, without prejudice, the proposed tariff revisions associated with generator obligations within PJM because PJM has not met its burden to demonstrate the revisions are just and reasonable.

And seventh, and finally, the order states that the PJM should consider the use of pricing or targeted revisions to its mitigation and recognizes operating reserve deficiencies in its market design. PJM is directed to file such reports on this investigation. That concludes our presentation.

CHAIRMAN WOOD: Thoughts or comments.

COMMISSIONER BROWNELL: Just a couple of comments. One is the idea, even as a last resort, that the ISO RTO should be in the marketplace is disturbing. I just want to say that I would look very closely because I think, if there is any indication that we'll begin to rely on that, we will not be sending the message that was loud and clear from the financial community. Testimony on this that we need to get the correct financial incentives. We can't rely on volatility. And it strikes me that if there non-investment dollars there in a marketplace to deal with reliability, something is fatally wrong with the market itself. I know we left the option open, but I'd be pretty concerned if people had to start exercising that option.

Further, I think this has been, albeit, not a massive problem in PJM and other places, it is a problem. We've heard consistently throughout the marketplace that compensation has been inadequate. We've also heard that generators have been intimidated in terms of identifying those costs and coming in here and I think this order makes it clear that we're going to have more transparency on this. We're going to look at the data, make sure we understand it and that the generators really need to feel comfortable about coming here for resolution if they can't find it in the marketplace. I think this is a good order. I'm not sure we've gotten the silver bullet on this issue yet, but I think everybody's worked very hard to get close to it and I hope this is part of our learning experience, actually, so that we can get a little more sophisticated in terms of our own analysis.

CHAIRMAN WOOD: I appreciate the work on the framework and I think we'll probably be using that in New England in the very near future -- pending case and we'll be using this framework -- I should add, and it really is buffeted by what we heard from the three market monitors today that the first line of inquiry in this kind of decision-making tree is, should there be further improvements to the market design, which is, I think, underpinning Norm's point.

And we heard today, thankfully, from all three regions in very different positions from where they are, that that is the right way to fix it. That's kind of like saying you really should eat your spinach, but it actually has not been that evident from the track records so far that people would favor bandaids and paper clips as opposed to just getting the surgery and getting it underway.

I think that the approach we have taken in numerous cases in the time that I've been here, if not before, to looking at the core market design. Is the market sensible? Does it send the right incentives to investors? Does it send the right messages to customers and everything else in between? Is the core issue we must be about? I'm proud that we are about that because we are on so many cases but there will be times when we get to the bottom of the day and you just have to do, not an RMR -- what do we call them now?

MR. PERLMAN: Reliability Compensation Issues, RCI.

CHAIRMAN WOOD: An RCI kind of thing and that's okay. I think we've done it in a thoughtful way here and, hopefully, that will be the exception and not the rule. When it's the rule, it becomes problematic. But nice job on the analysis. I appreciate the work as well as the other numerous cuts in this very important order, David, David,

David and Alice.

Let's vote.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The final item in the discussion agenda is E7. Also, a PJM interconnection ERO4608. It's a presentation by Michael Lee, accompanied by Valerie Martin, Gloria Miller, Jason Stanick and Michael Goldenberg.

MR. LEE: Good afternoon, Mr. Chairman and Commissioners. On March 1, 2004, PJM filed a proposal to implement market rules for behind-the-meter generation. This proposal will allow market participants to net operating behind-the-meter generation against load at the same electrical location for purposes of calculating applicable PJM charges.

Under the proposed market rules, load-serving entities will be permitted to net behind-the-meter generation against load in the calculation of charges for energy, capacity, transmission services, ancillary services, and administrative fees.

PJM's netting program is consistent with the Commission's goal of encouraging load reductions during peak demand by providing compensation to qualified generators that are running during these periods.

Accordingly, the draft before you accepts the market rules, subject to PJM filing a status report of the results of the stakeholder process by January 1, 2005, explaining whether the netting program could be expanded to include some generation associated with distribution systems. This concludes our presentation. Thank you.

COMMISSIONER KELLY: I think it's really important to highlight this Order. It is consistent with the Commission's demand response interests, and the way this issue has been handled, we would anticipate that it would encourage more use of behind-the-meter generation by reducing the costs of PJM charges and, in turn, as you mentioned, encouraging the use of this kind of generation during times of scarcity and high prices.

I'd also like to note that the proposal had broad support among the PJM stakeholders, and, in fact, all the parties to the proceeding supported the use of behind-the-meter generation to net generation against load.

I'm also encouraged that the stakeholder process is going to continue to look into the possibility of doing the same with certainly municipally-owned generation, and I hope that when PJM reports back to us at the beginning of next year, there will be a proposal attached to further expand the program. Thank you.

CHAIRMAN WOOD: Thank you. Let's vote.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

Meeting adjourned.

(Whereupon, at 2:55 p.m., the meeting was adjourned.)