BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

888TH COMMISSION MEETING

OPEN MEETING

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

Wednesday, May 4, 2005
10:17 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

SECRETARY MAGALIE R. SALAS

ALSO PRESENT:

JANE W. BEACH, Reporter

P R O C E E D I N G S

(10:17 a.m.)

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

Let's start with the Pledge to the Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Before we do the consent agenda, I wanted to make a couple of announcements. The first is that on our web page, we have a new item of historical interest. We've been a critical player, of course, in disclosing the role that Enron and other energy providers played in exploiting and exacerbating the energy crisis in California and in other western states in 2000 and 2001.

The Commission has collected and analyzed more than five terabytes of data, issued subpoenas and show-cause orders, and held hearings over the course of many months.

To date, the result of this unprecedented and comprehensive investigation has been $4.3 billion in monetary settlements stemming from the crisis, and findings by the Commission contributed to numerous prosecutions by the Department of Justice, and $300 million in civil penalties imposed by the CFTC.

Significant proceedings are still underway at the Commission, and a final Commission Order directing refunds for power sales in the market during 2000 and 2001, is still pending.

And in the Enron market gaming proceeding, FERC administrative litigation staff is moving forward there on a number of items, as well.

So we thought it was a good time to put a detailed chronology of all these activities, since people do tend to forget, and others tend to write history with a little more fiction than fact. So we thought we'd get out the facts there, and so please go to our website, and there is a link on there from the front page to the Electric Industries subpage, and the several-page document that walks you through the factual history of the western investigation.

A second item is on power shortages. As we look ahead to the Summer -- and I think we got a pretty good report at yesterday's NERC meeting, but we know there are some potential parts of the country where there might be some trouble, which we'll talk about later in this meeting.

I did want to say that Section 202(g) of the Federal Power Act, which implements Section 206 of PURA, requires the Commission by rule to have each public utility report promptly to the Commission, any anticipated shortage of electric energy or capacity which would affect that public utility's ability to serve its wholesale customers.

In conformance with the statutory provision, our regulations, which were adopted many years ago, Part 294 defines anticipated shortage of electric energy and capacity and sets forth reporting requirements for public utilities.

Among other things, a report filed pursuant to Part 294, must include the nature and projected duration of the anticipated shortage, a list of customers likely to be affected by it, and procedures for accommodating.

So, to implement this requirement, the Division of Reliability has set up a pager that transmits e-mail messages to an employee on duty at the time the notification is anticipated. This pager is carried 24/7 by the Division, in order to ensure that the bulk power supply shortage information can be sent by the utility and received by FERC at any time, and that FERC can, therefore, use it in the context of our interactions with other federal agencies to try to ameliorate or address these crisis or shortage situations.

The emergency e-mail address is emergency@ferc.gov, and we will, in the near future, be changing our rules formally through an instant final rule, procedural rule, to add that e-mail address as an additional way of complying with our year's long requirement that utilities report such information promptly to the FERC, so that we can work with both other FERC-regulated entities such as ISOs and RTOs, as well as work with NERC, with the Department of Homeland Security, and with state and local officials on these important issues.

We hope they don't come up, but if they do, we want to have the right information.

Madam Secretary?

SECRETARY SALAS: Good morning again, Mr. Chairman, and good morning, Commissioners. The following items have been struck from the agenda since the issuance of the Sunshine Notice on April 27th; they are: E-1, E-2, E-28, E-34, E-62, E-63; G-18, and G-20.

Your consent agenda for this morning is as follows: Electric Items - E-3, 4, 9, 10, 13, 14, 16, 17, 18, 19, 20, 24, 26, 27, 29, 32, 33, 35, 36, 37, 38, 39, 40, 41, 42, 43, 46, 47, 48, 51, 51, 55, 57, 58, 59, 60, 61, 65, and 66.

Gas Items: G-1, 4, 6, 7, 9, 11, 12, 14, 15, 17, and 21.

Hydro Items: H-1, 2, 3, 4, 5, 6, and 7.

Certificates: C-1.

As required by law, Commissioner Kelly is recused from the following items on the consent agenda: E-3, E-4, E-19, E-36, R-51, and E-65.

The specific votes for some of the items on the consent agenda are: E-3, Commissioner Kelliher dissenting, in part, with a separate statement; E-4, Commissioner Kelliher dissenting, in part, with a separate statement; E-14, Commissioner Kelliher dissenting, in part, with a separate statement; E-33, Commissioner Brownell concurring, with a separate statement; E-37, Commissioner Kelly dissenting, in part, with a separate statement; E-38, Commissioner Kelly dissenting, in part, with a separate statement; E-39, Commissioner Kelly dissenting, in part, with a separate statement: E-40, Commissioner Kelly dissenting, in part, with a separate statement; E-55, Commissioner Kelliher dissenting, in part, with a separate statement; E-59, Commissioner Kelliher dissenting, in part, with a separate statement; G-1, Commissioner Brownell dissenting, in part, with a separate statement; G-4, Commissioner Brownell concurring, with a separate statement; H-2, Chairman Wood dissenting, in part, with a separate statement.

Commissioner Brownell votes first this morning.

COMMISSIONER BROWNELL: Aye, noting my dissent on G-1 and concurrence on G-4 and E-33.

COMMISSIONER KELLIHER: Aye, noting my partial dissents in E-3, E-4, E-14, E-55, and E-59.

COMMISSIONER KELLY: Aye, with the exception of the recusals and the dissents noted by the Secretary.

CHAIRMAN WOOD: Aye, with the dissent, in part, on H-2.

Before we go on, I wanted to comment on a couple of items, just to report, publicly, what happened on two groups of items. The first is E-35, which was a remand in the Nevada Power Company case, which was captioned before the D.C. Court of Appeals as Entergy Services v. FERC.

This remand order explained why the Commission policy that network upgrades include all facilities at or beyond the point at which a generator connects to the grid, is a reasonable policy. This order applied our current policy that the cost of interconnection facilities should be paid by the interconnection customers because they are the ones who benefit from the upgrade, but that the cost of network upgrades that provide a benefit to all transmission system users, should be paid for by all transmission customers.

This Order clarified that when a preexisting substation is used for the interconnection, substation upgrades benefit all customers. And then in the series of market-based rate Orders, we continue our implementation of policies that were adopted over the past three years, relating to the ability of wholesale electric power companies to sell at market-based rates, if they and their affiliates do not have or have adequately mitigated market power in generation and transmission and cannot erect other barriers to entry by their suppliers.

The Commission also considers whether there is evidence of affiliate abuse or reciprocal dealing. The following actions on market-based rates were taken today: In E-3 and E-4, the Commission granted, in part, and denied, in part, a December Order in Entergy and Southern Companies, relating to their market-based rates in the 206 proceeding that have been initiated thereunder.

We had granted a new request for market-based rates to Public Service Electric and Gas Company and PSEG Energy Resources in E-17. And in E-9, we accepted updated market power analysis from Portland General Electric Company, Oregon Electric Utility Company.

Also, on E-20, with Reliant Energy Cool Water, and Black Hills Colorado in E-29. In E-30, we conditionally accepted updated market power analysis from ConEd of New York, and in E-26, 27, and 65, we initiated 206 proceedings, requiring updated market power analyses from LG&E Energy Marketing, Pacificorp, and PPM Energy and Progress Energy, Inc.

And I think Joe had some thoughts on E-30.

COMMISSIONER KELLIHER: Thank you, Mr. Chairman. I just want to make some comments about E-30, and some general issues that it presents.

In E-30, the Commission accepts and updated market power analysis submitted by ConEd, subject to a requirement that ConEd file information that they were actually required to file nearly two years ago. And this Order highlights a problem that exists on the Commission's current market power test.

Public utilities are authorized to charge market-based rates -- public utilities that are authorized to charge market-based rates, are required to submit an updated market power analysis at the end of a three-year period.

If that analysis demonstrates the absence of market power, or if they mitigate their market power, the applicant can continue to charge market-based rates, but, otherwise, absent that kind of showing or mitigation, the Commission may initiate a 206 proceeding and revoke their market-based rate authorization.

In this instance, ConEd was required to file an updated market power analysis on June 9, 2003. It did not do so. In fact, Con Ed waited 17 months until November of 2004, to file its analysis.

In even analysis it eventually filed, was woefully deficient. The Commission Staff invested their time and energy, repairing the deficiencies in ConEd's filing.

So, ConEd's filing was both late and deficient. I don't know why ConEd ignored the Commission's deadline. Perhaps it's arrogance; perhaps it's indifference, or perhaps it's sheer incompetence, but I don't think it really matters, why they were late.

It just matter that they were late and deficient. And I think the Courts have told us, as recently as last year, that the Commission needs to have strong regulatory requirements to ensure that public utilities with market power, cannot exercise market power.

In my view, that means assuring that market-based rateholders that ignore filing deadlines such as the triennial review, cannot continue to charge market-based rates. And that can be accomplished in a number of ways: One, the Commission could perhaps sunset the market-based rate authorization, so that it ends at a certain date, putting the onus on the holder of market-based rates to file in a timely manner, since there would be consequences for failure to file.

Or the Commission could perhaps provide for an automatic Section 206 proceeding, if the updated market power analysis is not filed in a timely manner.

It's important to remind people that market-based rates is a privilege and not a right, and that late filers, in my view, should be exposed to disgorgement of profits, and perhaps that would induce timely filings and complete filings.

Now, ConEd apparently is not the only offender. We've seen a number of late filings in my brief time, relatively brief time here, and apparently Commission Staff has been looking into this and has found, actually, a pretty large number of late filings.

I was going to say that ConEd may be the worst offender, but now we know that they're not, that there are many other entities that have been much later than 17 months.

So, I think it's a generic problem. It kind of is highlighted by the ConEd Order, but after further inquiry, we know that ConEd is not alone, and that perhaps the Commission should take some action to induce filings. I think that, in the course of the rulemaking, we should address this issue.

So those are my comments. Thank you.

CHAIRMAN WOOD: Great, thanks, Joe. In light of the inquiry that Joe talked about, we've identified well over 100 companies that are either deficient or have not filed at all, including a couple of the others on the list today -- Progress Energy and LG&E, for sure, had either deficient or late filings and 206s were initiated there.

I would recommend -- and, Cindy, if you could work with the market-based rate team on identifying these, but I think, as we did last year with the EQRs, let's issue a proposal to suspend under Section 206, all the people who are late, and just kind of generically deal with this, and then make it part of our going-forward process, that when we haven't heard from somebody on their third anniversary or whenever they're required to file, that we, as a matter of routine process -- and I would say that we could probably put this under delegated authority, even, initiate a 206 to suspend the operation of the market-based rate authority, so that we get clear compliance with that.

Otherwise, I think Joe's recommendation about finding some way to sunset, which I know is a little awkward, might be a good way to move forward, but, in lieu of that, I think that just being alert to the people we have and when their anniversary dates are, would be a good way to ensure compliance.

It's not productive to spend as much time as we've had to spend rehabilitating either deficient filings or trying to find out where the filings are in the first place.

Sudeen?

COMMISSIONER KELLY: Mr. Chairman, I'd like to add comments to E-35. In large part, this case was remanded to us because the Court acted on a presumption that was erroneous. We explain it in the Order, and I'd like to clarify that here.

The Court in this case presumed that interconnection facilities must be located at the point of interconnection, however, rarely is the point of interconnection located at the generating facility itself. In virtually all cases, interconnection facilities, for example, a radial line, poles, support switches, meters, must be constructed to provide an electrical connection between the generating facility and the transmission system at the point of interconnection.

Thus, when we refer to interconnection facilities, we are not referring to facilities at the point of interconnection, but rather to all facilities and equipment from the generating facility, up to, but not including the point of interconnection.

Now, the Court in this case got it wrong and remanded it to us, but we explained that in our Order, and, therefore, the $3 million in direct assignment interconnection costs at issue in the Consumers Energy case, which was precedent for this case, were not costs for facilities at the point of interconnection.

And Consumers Energy, therefore, is consistent with the policy which we also applied to Nevada Power in this case.

CHAIRMAN WOOD: Great, Sudeen. Thank you. I wanted to add one more item that was also on the consent agenda, that is of interest.

In E-66, the Commission initiates under Section 206 of the Federal Power Act, an examination of affiliated abuse concerns within the Southern Company system.

Specifically, the Commission will investigate the justness and reasonableness of the Southern pooling agreement, which is referred to as the Intercompany Interchange Contract, whether there are any violations of the standards of conduct and whether the code of conduct that is employed there, is just and reasonable.

This relates to a creation of NUCO, which has since become Southern Power Company in a May 2000 compliance filing with the Commission. And the evolution of that relationship since that time, will be investigated in the proceedings begun in E-66.

So, I think that's probably all the main items. There are a lot of other interesting things in there, and I want to thank again, the hard work of the Staff and our own Staffs up here to get through a significant number of Orders that really do, again, continue to erode away at our ever-decreasing backlog and get us current on all of our items. We appreciate the hard work that everybody does to get that done.

SECRETARY SALAS: Mr. Chairman, for the record, on E-3, I need a vote, so if we can go ahead and vote?

COMMISSIONER BROWNELL: Aye.

SECRETARY SALAS: That was your first item for discussion. It was not part of your consent agenda.

CHAIRMAN WOOD: Ah-ha, got it.

COMMISSIONER KELLY: Aye.

COMMISSIONER KELLIHER: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: Great, thank you. The second item for discussion this morning is A-5. This is NERC Compliance Audits. This is a presentation by Mr. David Hilt from the North American Electric Reliability Council.

CHAIRMAN WOOD: We welcome back the former Deputy General Counsel of FERC, and now General Counsel of NERC, Mr. Cook.

MR. COOK: Thank you, Mr. Chairman.

MR. HILT: Good morning, Mr. Chairman and Commissioners. I think I have a presentation, if it can be put up on the screens, please.

(Slide.)

MR. HILT: Thank you. Today I want to just provide a very brief and high-level overview of the results of our 2004 compliance enforcement program in which we monitor compliance with a number of our standards.

Of course, much more detail is provided today on the NERC website in terms of our quarterly reports through the recent adoption this past year of the disclosure guidelines by our Board, and there will ultimately be, very shortly, a final 2004 program report to compare to the other annual reports that are up on our website.

Next slide, please.

(Slide.)

MR. HILT: I want to give a little background on what we actually monitor in the compliance program. Much as it was with the securities industry, as we patterned our compliance program after, there are many, many rules within our book of rules, if you will.

And if you look at the new standards that the Board recently adopted, there are 91 standards, over 800 requirements in those standards, and we have to selectively do a little work with the monitoring.

Some of those are monitored every year in the program; some of them are periodically monitored on a rotating basis. The key is that we want to make sure that they're very central to reliability.

A number of the standards themselves, build upon each other. For example, in the area of balancing resources and demand, there are a number of requirements for generators and balancing authorities to include on their equipment to be able to balance actively, the generation and the load, but what we really monitor is the performance of that, which was called control performance.

As we go through this, we don't actively monitor every little piece that builds on that. The standards vary. Many of them are event-based, for example, from operating security limits. If someone goes over an operating security limit, that would be an event-based.

Others are monthly, such as, did you have NERC-certified operators on duty throughout the entire month? Others are quarterly, and some are even annual, primarily in the planning arena.

Next slide, please.

(Slide.)

MR. HILT: The monitoring is accomplished through our regional programs. We have ten regions that monitor directly with their members. We use a good deal of self-assessment and self-certification on the ongoing basis.

They are backed up by a three-year periodic audit of compliance with the particular rules, and, finally, there's often investigations. If an event occurs or if there's a complaint, that can trigger investigation within a region.

The regions report those violations now directly to NERC, and we post quarterly and annual performance reports on the NERC website. The first four quarters are now up on the website, with the last two including the names of the violators, as approved in our disclosure guidelines.

So, what are the results? Next slide, please.

(Slide.)

MR. HILT: In 2004, 318 violations of the NERC standards were identified through the compliance program. That's down from 360 that were in the 2003 program.

The results are very encouraging. We need to recognize that, as I said, some of the items rotate in and out of the program, some of them have not been monitored for several years, so we include them back in the program, so it's a little hard to do some very, very direct comparisons.

But when we do do a direct comparison, for the same measures that were in the program in 2003 that are in it in 2004, we saw a 33-percent reduction in the number of violations for those specific measures.

That may seem like a lot of violations, 318 for the year, but we have to remember that in the past year, there were 150 control areas and 18 reliability coordinators that we're monitoring to the 40-plus compliance measures that are in the program.

There are several hundred requirements. Some of them are event-based, so there's many opportunities for an operating security limit violation on a particular line at any particular time, and so there are many opportunities for violations.

Next slide, please.

(Slide.)

MR. HILT: This slides shows the improvement in compliance with some of the key measures in the planning area for 2003, as compared to 2004.

In last year's program, we highlighted some measures that we thought had a fairly high number of violations, and, again, we're going to highlight those in our final report. You will see this table, but certainly it shows that there has been an overall reduction in some of these measures in terms of improvement. These are primarily related to system protection testing and under-frequency load-shedding programs being fully compliant with the requirements.

Next slide, please.

(Slide.)

MR. HILT: Compliance with some of the key operating measures also improved in 2004, and these are related to control performance, security limits, and operator training and certification.

And we did see significant improvements in those areas, as well. Next slide, please.

(Slide.)

MR. HILT: In addition to those that are in the program on an annual basis, we have been monitoring compliance with the cybersecurity standard that we developed with some assistance with those here at FERC a couple of years ago.

This is the second year that we've monitored the compliance with this particular standard. We've seen significant improvements in the results with that. At the beginning of 2004, in January, we had 67 percent overall compliance with all 16 of the requirements.

At the beginning of 2005, that has improved to almost 90-percent compliance with all 16 requirements, with many of the requirements having 100-percent compliance now. Next slide, please.

(Slide.)

MR. HILT: In addition, we've been monitoring compliance with the vegetation outage requirements. The standard itself that we have, has two requirements that are related to some work that the FERC here has done.

The first part of it has to do with making sure that everyone has a vegetation management plan and an annual work plan for maintaining the vegetation out of the right of ways.

We found no violations of that, and I think that confirms the work that you had done in collecting many of those from the entities that are responsible to FERC.

We went one step further with ours and had reporting of all vegetation-related outages in a couple of categories around EHV transmission lines as part of our blackout recommendations. In 2004, there were 38 such outages reported to NERC. This slide shows the total number within the right-of-way and adjacent to the right-of-way and how many outages per hundred miles of transmission were actually reported to us in 2004.

This being the first year that we've collected this data, it will be very interesting and we certainly hope to look at trends in this data -- and hopefully it will be downward. However, we did look at each one of the outages, we have some detail on all of these 38 outages and we believe in every case that the tree or the situation has been resolved.

And with that, Mr. Chairman, I'd be happy to answer any of your questions that you may have.

CHAIRMAN WOOD: David, thanks a lot. I appreciated your presentation yesterday to the NERC board as well on similar matters.

I wanted to follow-up on the cybersecurity first. You mentioned yesterday and I wanted you to just share with my colleagues and our staff here today what's going on with the development of I think a higher standard and what's the kind of timetable on that.

MR. HITT: Yes, the Standard 1200, the cybersecurity standard we have now was developed under the urgent action provisions of our standards development process. That standard is set to expire in August, mid-August. We've been actively working for the last two years to put together a much tougher standard, a more detailed standard that applies in a broader range of entities in the electric business and they're very much on track to have that accomplished. Unfortunately, I think we're going to have a little issue with -- this standard may expire in August and the schedule right now is some time in November we expect to have the new standard in place.

We're looking at options as to how to extend this standard to make sure that we do have a standard in place during that interim period and will report back to our board at their August meeting on those options as to which one we will be taking. But we certainly expect to continue with cybersecurity standards in the future.

CHAIRMAN WOOD: And then actually the development of the next generation standard. I mean, are there specific matters or specific items that you see that addressing that will be an improvement over the current 1200 standard?

MR. HITT: Well certainly the number of people that are -- the number of entities that are covered by that standard. Today we monitor reliability coordinators and control areas and with the new standard we will certainly drill that down to others that are involved in the electric utility business. As you know, with cyber you don't necessarily have to go in through the largest door into the system to get in, so we're anxious to get that standard in place.

CHAIRMAN WOOD: I've noticed and announced our staff to pull off the reports from the four quarters of last year on the compliance and I just want to say as one who's watched this program as you've lived it, David, grow over the last year, particularly with the searing spotlight of your board on it. To go to naming names, I think was a critical thing. I remember specifically praising the actions of the Board last summer when they agreed to do that with the appropriate amount of due process for the people that were kind of swept up in the compliance findings, and I just want to recommend for the public to look at the NERC.com webpage under the compliance tab, I believe it is.

MR. HITT: Yes.

CHAIRMAN WOOD: And these reports are on there, I don't think it's my job to name these names in the microphone here, but they're there and I think -- I can't imagine a more effective enforcement regime than for a CEO to see his company's name on the cover of the NERC public disclosure compliance list. I would hope that the scarlet letter factor continues to work as well as it has.

Again, I look forward to the day when there is reliability legislation to solicit by this but I do think this has filled the breach in the most effective way and I just want to continue to urge both your professional labors to it, David, but also that of all the people who are involved in the compliance program. It is a central function that you-all do that we certainly, on the government side of the fence, can't duplicate. We want to support it and we want to help you, do what we can on our side but it really takes the professionals that are looking at the detailed implementation of all these standards to really ensure that we have a safe and secure grid. So thank you very much, on a personal and professional basis, for what you-all are doing with regard to the compliance and to the naming names. It is absolutely critical to making sure that the events of August of '03 never happen again. So I'm thrilled to see it actually in hard copy. Thank you.

COMMISSIONER BROWNELL: I have a question. David, I agree that I think that it's appropriate for an independent oversight agency as you wish to be to actually hold people accountable by naming names. Are you working with NARUC and the individual state commissions to make sure that they have a full understanding of what these violations mean so that they can increase their vigilance?

MR. HITT: Yes, we are. Every quarter, when we publish this report, we send specifically to a list of state regulators the report on the violations and we've held -- at the last quarter in particular we held a webcast for the NARUC staff folks to help them understand what the violations mean. Every way we can, we certainly want to work with them as well.

COMMISSIONER BROWNELL: David, you mentioned in one of the reports, I think it's the fourth quarter report, that you are getting fuller explanations from the regions about the meaning of the violation. What exactly -- that may or may not be perceived as having an impact on the system. So I'm assuming that the companies -- or what does that mean actually?

MR. HITT: Well originally when we started this, the bar was was it significant to reliability or was it not significant, and many of the responses came back well it was -- at the time that this occurred, it was not a threat to reliability. And we asked for more explanation to provide the public with some better understanding of what -- to put the violation of the standard in particular context, and the regions have dutifully provided that for us.

COMMISSIONER BROWNELL: And then do you validate that, is there an independent validation of that in any way?

MR. HITT: At this time, our board, the NERC compliance staff reviews those and either concurs or does not concur with them. As we move forward, we're working on a process that was discussed at our stakeholders meeting yesterday to try to put some more context around the violations and I think there were some concerns at that meeting -- trying to put essentially some numerical process to it, to put a score to a violation, if you will. There were some concerns there that a low score might mean that the violation really wasn't significant and there were some concerns at that meeting that all violations are of some significance. So we'll continue to work on that but we're looking at ways to make it a little less arbitrary and put a little more structure into determining the significance of the violations.

COMMISSIONER BROWNELL: Good. I think that's important. I think it is tough and it's probably tough to assign some numerical thing, but we don't want a situation where reliability is in the eye of the beholder; I think that puts us at some degree of risk.

One more quick question: when you list these violations, am I to assume then on the rotating look-see these are the people who appear -- who get looked at more frequently rather than less frequently? I mean, are there certain kind of categories, for example, operator certification, I would think that would be -- you have three weeks to follow-up and outline your training program. I mean, do you go -- are those the people that rotate more quickly get a better look?

MR. HITT: Yes. The intent of the program is we will follow those very, very closely. In many cases, the operator certification is a matter of having an operator that can -- we have a test that an operator must take and pass --

COMMISSIONER BROWNELL: I just used that as an example.

MR. HITT: That may take some time if the individual cannot pass the test, then they may have to find another individual that can.

COMMISSIONER BROWNELL: But they can work until -- like --

MR. HITT: They can. It's a violation of the standard to have someone on a desk that's not a NERC-certified operator.

COMMISSIONER BROWNELL: How many times can they take the test?

MR. HITT: I'd have to look, but they can take it several times.

COMMISSIONER BROWNELL: So meanwhile are they supervised with someone who has passed the test?

MR. HITT: There should be someone in the control rooms at all times that has passed the test, yes.

COMMISSIONER BROWNELL: I hope so.

COMMISSIONER KELLY: I wanted to follow-up on Nora's lines of questions, David. In your third quarter report of 2004, you noted that the board of trustees had asked the compliance and certification committee to develop metrics and definitions that could be used to assess significance on a consistent basis. You just talked to Nora about the recent stakeholder process. Was there a consensus that came out of that process that that shouldn't be done?

MR. HITT: No, not at all. The consensus out of the process was it needs to be done but it needs to be done very carefully.

COMMISSIONER KELLY: Right.

MR. HITT: And we'll continue to work on that. It is going to take some time, because any time that you draw a line in the sand and you say this is this level of significance or not, we have to be very careful that we're doing it appropriately.

COMMISSIONER KELLY: I understand that. But I do want to stress that I think that that is very important because indeed violations are -- some are more significant than others, and particularly when the reliability of the grid is at stake here it's important to know which ones are exceedingly significant because they should be getting a great deal of attention, not only from NERC but also from us. So I appreciate your efforts in that regard and I hope that the committee can move quickly to develop standards. Thanks.

COMMISSIONER KELLIHER: I wanted to ask you a question about whether you will try to identify levels of severity or seriousness of violations. In the nuclear energy context, I think the NRC has two or three different levels of reporting violations. They do some triage. And your reports are -- they give you a gross number and they identify the areas where there are violations but not really a sense of which violations are serious, which ones are less serious. Will you be doing that?

MR. HITT: That's the intent of this entire program is to put them into context in terms of looking at what other -- you know, in combination with another violation, would this have been significant, in combination with the current system conditions, you know, had it occurred on an April morning when loads were incredibly light it may not be of as large a significance as it may be at peak load periods. The answer is we do have some significant levels in there today, in terms of level I, II, III, and IV with how egregious the particular violation is that we want to go one step further with categorizing them and looking at them in context with other potential violations.

COMMISSIONER KELLIHER: But just to be clear, will you then have more than one category of violations then?

MR. HITT: Yes, certainly.

COMMISSIONER KELLIHER: Right. And since you rely on the regional reliability councils to report to you, do you in turn assess their enforcement informally or formally assess their enforcement ability?

MR. HITT: We do that on a formal basis. The NERC compliance and certification committee is charged with auditing each of the regional compliance programs. Annually they submit to us a program plan for how they're going to carry out their program. We review that and will approve their plans if appropriate. This year we had some issues with them in terms of disclosure and asked for revisions in their plans. We do not audit everyone every year but we do that also on a three-year cyclic basis where we will go perform an audit of the regional program to see that they're carrying it out in accordance with the program plan that they submitted to us.

COMMISSIONER KELLIHER: And when you suggest improvements, what occurs? Do they make the improvements?

MR. HILT: Today, as we've gone back, we're on our second round of audits on those regions, and, generally, yes, we've seen that they have taken our recommendations to heart, and implemented them where it's been appropriate to do so.

COMMISSIONER KELLIHER: Okay, thank you.

COMMISSIONER BROWNELL: Are you publishing the results of those audits, as well?

MR. HILT: We have not. We haven't broached that thought, but that's a possibility. Those have been certainly internal to NERC. We've not made those public, but that's another issue that we may want to consider.

COMMISSIONER BROWNELL: You probably ought to take a look at that. Maybe your Board wants to do that.

I think the Blackout Report raised some pretty serious questions about the independence of those regional groups, and I think it would probably do everyone a service, to kind of give information.

As long as we're holding companies accountable, we ought to hold the rest of the world accountable, as well.

MR. COOK: If I could follow up, Commissioner Brownell, in response to those discussions in the Blackout Investigation Report, the regions have taken on a study of the role of the regions in identifying the functions that they're performing, and then set some criteria down about the things that they ought to be doing.

They've done sort of a gap analysis of where particular programs need to be brought forward and enhanced, and that process is underway. We had a final report from the group that did that study, at the Board meeting -- rather, at the members meeting on Monday.

And that report is or will be public, and so there's sort of another measure of the focus that's going on in the regional programs.

COMMISSIONER BROWNELL: And so that report will be public in the next month or two, and then the regions will make the appropriate changes? It's been awhile since that Blackout Report was issued.

MR. COOK: It has been, and it's my understanding that the regions have programs underway to close the gaps, where they have been identified, but that information is generally public. It was available at the meetings and so on, so I just physically don't know whether it's been posted or not, but it's certainly public information that's available.

COMMISSIONER BROWNELL: And has the team, the DOE, FERC, other people team that drafted the Blackout Report and made those recommendations, have they looked at that; have they been asked for their opinion in terms of whether that meets --

MR. COOK: They have not. We've not asked them formally for that, and they have not made any findings in that regard.

They have a report underway themselves, I understand, that should be out in -- I don't mean to put deadlines on them. I think it's like the next month.

COMMISSIONER BROWNELL: So we assume they're looking at it, or not?

MR. COOK: I assume they are, but I don't know the answer to that question. They were -- some of representatives of them were at the meeting where it was discussed.

COMMISSIONER BROWNELL: It strikes me as a way to validate the work that the regions have done, particularly since they have come back together and are working, I think, under the Office of Transmission at DOE. Perhaps you want to ask them to undertake that task.

MR. COOK: I'll certainly make sure the regions get that information to them for that.

COMMISSIONER KELLY: David, again in your third quarter 2004 report, you noted that the Western Electricity Coordinating Council did not state whether the violations that occurred in the WECC region, were significant or not.

They just didn't comment.

I have a couple of questions regarding that: Has WECC since commented on whether or not they were significant?

MR. HILT: WECC has begun to provide us with that -- with some discussion of the significance of those violations. There was some need to establish some processes within regions, in response to the disclosure guidelines. It just took a little longer in WECC to get them in place.

We fully believe, you know, our review and discussion with WECC at our Board meeting yesterday, was very, very positive and they are providing all of the information that we're asking for now, in a very, very timely fashion.

COMMISSIONER KELLY: Great. And of the violations that they have talked to you about, do any of them rise to the level of concern, significant concern?

MR. HILT: Certainly all violations are of concern.

COMMISSIONER KELLY: Right.

MR. HILT: But none of the violations that have been identified to date, rises to the level of what I would label as a significant concern.

COMMISSIONER KELLY: And WECC has confirmed that with you, that even though it's not in the report, it's been reported to you?

MR. HILT: It has been reported to us, and there is some in the third quarter, but if you look at the fourth quarter report, they did provide some context for the particular violations.

COMMISSIONER KELLY: Thank you.

COMMISSIONER KELLIHER: I just wanted to come back to urge you to really move ahead on trying to come up with categories of violations.

It kind of brings to mind, a comment that Marion Barry had made a number of years ago when he was Mayor, and he said, except for the murders, the D.C. crime rate had fallen.

(Laughter.)

COMMISSIONER KELLIHER: And it's useful to see that the total violations have fallen from 360 to 318, but it could be that the subset of serious violations might have increased, and I think it would help build confidence in the reporting, if you were to try to categorize the violations.

I had another -- just one question on the vegetation outage reporting slide. When you say that no violations of requirements were reported, what requirements are you referring to? There's not a vegetation management standard, right?

MR. COOK: There were some vegetation management requirements developed as a result of the blackout, that were translated into the standards, the Version 0 standards now. And it included just the basic requirements that you have a vegetation -- that the company have a vegetation management plan, and an annual work plan, and there were some requirements within what needed to be in the annual vegetation or the vegetation management plan.

And we had identified no -- everyone was fully compliant with those requirements.

COMMISSIONER KELLIHER: Thank you.

CHAIRMAN WOOD: Gentlemen, thank you for coming up. We appreciate it.

MR. COOK: Thank you.

SECRETARY SALAS: The next item for discussion is A-4. This is State of the Markets Reports.

This is a presentation by David Patton and Steven Balser, representing the NYISO, Bob Ethier from the ISO New England, Anjalie Sheffrin and Greg Cook, representing CAISO. And we will start with California ISO.

(Slides.)

MS. SHEFFRIN: Good morning. I'm Anjalie Sheffrin, and this is Greg Cook. We're from the California ISO. Thank you for inviting us here this morning.

We're here to review with you, the state of the California markets in 2004. I will review the overall market performance, and I'll cover two areas: How the markets have performed, and, second, what issues we analyzed in 2004, in order to help improve the operation of the market.

When we look at market performance, there are three areas that we focus on: First, were the costs to serve the load stable, the wholesale energy costs, were they stable?

Second, were the markets competitive; third, what was the level of reserves? Did supply keep pace with demand growth?

After a few summary slides on this indicators, what I'll do is cover four market issues that we analyzed: First, what was the impact of the new Phase I-B Market Design that went into effect in October of 2004?

Secondly, what were the sources of rising real-time congestion costs that we saw in 2004?

Third, why did we see a number of hours of ancillary service bid insufficiency in the markets, and;

Fourth, what is the outlook for the Summer of 2005. So, I hope to cover these issues in my presentation.

Let me begin with just a quick refresher on the Cal ISO in the markets that it runs: The Cal ISO covers about 75 percent of the load in California. The other 25 percent is covered by municipal control areas.

In 2004, the Cal ISO control area saw a peak load of 45,597 megawatts. Our load growth in 2004, was about 3.7 percent, and much of that occurred in Southern California, and you'll see this to be a theme of my presentation.

We had a high level of imports into California to help meet our peak loads. Actually, our imports from the Northwest declined by three percent last year, because it was a dry hydro year for the Northwest, but our imports from the Southwest increased 20 percent, because there has been a tremendous amount of new combined-cycle facilities that have been built in the Southwest region, and there's tremendous competition to get that supply into California to meet the Southern California load.

CHAIRMAN WOOD: What's the capacity of the transmission grid to get it there, Anjalie?

MS. SHEFFRIN: You'll see in my congestion slide that we do have some congestion, trying to get all that capacity in. And our Board of Directors just recently approved an increase on the Palo Verdes-Devers line and expansion. That's a major $690 million expansion, but that will be a few years down the road.

COMMISSIONER BROWNELL: A few is two or three or four, or?

MS. SHEFFRIN: I think it's supposed to come online in 2009.

CHAIRMAN WOOD: That's four.

COMMISSIONER BROWNELL: Okay, four.

COMMISSIONER KELLY: And does the Los Angeles Department of Water and Power, also have plans to increase the capacity into Los Angeles?

MS. SHEFFRIN: Well, we have competition between Southern California Edison and Los Angeles Department of Power, both wanting to build that line. We're hoping that they can work out an agreement, but it --

COMMISSIONER KELLY: But it would be one line that they're competing for, rather than two?

MS. SHEFFRIN: Right, yes.

COMMISSIONER KELLY: And who has jurisdiction over that decision?

MS. SHEFFRIN: Well, it depends. Because it's a contract between Southern California Edison and LADWP, if Edison feels that, you know, they have the contract rights, then it will go before the California Public Utilities Commission, but if LA feels that, no, they have the contractual right, then they can be their own lead agency in getting that built.

CHAIRMAN WOOD: Is there going to be another standoff then and it not get built at all?

MS. SHEFFRIN: No. We're hoping, since both parties want it built, that someone will build it. Right now, Edison is claiming that they have the contractual authority, but we're hoping that the lawyers will work that out.

COMMISSIONER BROWNELL: We've got a lot of hope in California for a lot of things. Give us -- I mean, who is going to make the cut? Let's --

MS. SHEFFRIN: Southern California Edison has already filed their application at the California Public Utilities Commission to build that line, so it is an affirmative action by that Company.

COMMISSIONER KELLY: And has LADWP intervened in protest?

MS. SHEFFRIN: I think that they issued a news release saying that their reading of the contract says something different, and Edison's response is that they're working with LA on that interpretation of the contract.

COMMISSIONER KELLY: And assuming that the line is sited and approved, what's your estimation of the construction time?

MS. SHEFFRIN: Actually, hopefully, if the approval process goes quickly, the construction won't take as much, because a lot of it is using existing right of way that's already been bought. You know, a lot of the regulatory approval is in the environmental impact arena, so we're hoping that it does get streamlined, but, as I said, the expectation is that it's on in early 2009.

COMMISSIONER KELLY: And does that line go into Arizona, or is it entirely within California?

MS. SHEFFRIN: No, there is a part in Arizona.

COMMISSIONER KELLY: And are you working with Arizona's local siting authorities, or the Arizona PUC, whoever would have jurisdiction, since there's not a regional entity that Arizona is a member of?

MS. SHEFFRIN: Southern California Edison is the lead agency proposing this line, so they would be working with those agencies, but in the regional transmission planning forums that the Cal ISO has participated in, certainly a lot of the Arizona authorities have been involved in that.

But, again, it's Southern California Edison's responsibility to make sure that all gets done on the Arizona side.

COMMISSIONER KELLY: Thank you.

(Slide.)

MS. SHEFFRIN: Okay, let me turn to the key parameters of market performance: The first one is overall wholesale energy costs. Again, they've been stable for the third year in a row, since the California energy crisis.

In 2004, wholesale energy costs were $12.8 billion, up one billion from 2003. A lot of that can be attributed to the rise in natural gas prices.

What's interesting to compare is, if you take a look at the total 2004 costs, and normalize them for natural gas prices for a year before the crisis, which is 1999, we actually see that the costs will be lower by about 30 percent than '99.

We looked into why is that, and what it reflects is the tremendous amount of generation efficiency that's occurred in the markets. In 1999, the average heat rate to serve load, was about 12,000 heat rate, whereas in 2004, that had fallen to about 9,000 to 10,000, so much more efficient generation having been built and meeting load.

One other thing to note on this slide is the blue area that is the forward energy that's contracted prior to the Cal ISO real-time market, so the majority of the energy needs is being bought in the forward markets, and only about two to three percent of the load is being met in our real-time markets.

(Slide.)

MS. SHEFFRIN: On the next slide, what we see here is, in terms of overall competitiveness, as measured by the price/cost markup, we've had the third year in a row of competitive market performance.

We saw prices in our market with only about a five-percent, on average, markup, over what we consider to be competitive benchmark costs, so this is, again, very competitive outcomes for our market.

(Slide.)

MS. SHEFFRIN: The next slide is turning to real-time prices. On average, they've been in the $40 to $50 per megawatt hour range, so, again, they have been fairly stable, compared to last year's.

In the fourth quarter, we did see real-time prices rise, and, again, this reflects a combination of factors. We had the new software go in, so some people thought, well, did this cause the price increase?

The second is, we had two large nuclear units, Diablo Canyon and San Onofre, out for refueling, and we had major maintenance being done on the major DC line from the Northwest into California.

And, finally, I think, as a lot of people remember, there was a big jump in natural gas prices, right between the end of September and early October. I think that, you know, all those factors really contributed to that increase in prices in real-time in the fourth quarter.

Not any one of those factors was the real reason. Again, I do want to remind you these are average prices over the month. We see individual hour price spikes, obviously. In our markets, they tend to occur during the hours of 6:00 a.m. and 10:00 p.m., and that's when these 6x16 block contracts come in to meet California load. So they tend to come in at 6:00 a.m. and there's a tremendous amount of ramping requirements and we tend to see the price spikes then and then they terminate at 10:00 p.m. and again there's a tremendous amount of ramping requirements in that hour and we tend to see the price spikes. So again these are averages but we do have individual hour price spikes when different certain system conditions warrant our needing more power on the system.

(Slide.)

MS. SHEFFRIN: Let me now turn to demand supply fundamentals. In California, we have seen a high level of load growth. This has particularly been the case in southern California and that load growth is occurring mainly in the inland areas: Riverside County, San Bernardino County, where it is hotter so it tends to contribute to our peak load growth with air conditioning demand.

At the same time, we did see a slowdown in our generation additions, and I'll show you a more detailed slide in a few minutes, but essentially our generation additions were only 568 megawatts in 2004. We do expect that to pick up for this year; by summer of this year we expect another 1780 megawatts to come on.

But again essentially what happened was load grew much faster than what generation supply came online. How did we meet, therefore, our load growth? Well, it was due to the increased imports from the Southwest.

COMMISSIONER BROWNELL: I just have a couple questions about that. You talk a little bit about the SoCal/Ed territory. You didn't include, I think, something that the Cal ISO presented to the California legislature which shows reserves in the SoCal/Ed territory only slightly -- under the one and two scenario, only slightly above what the desired 7 percent reserve, dipping pretty significantly in 2006, hugely underwater, in the worst case 1 in 10 really hot summer scenario in 2005. We're talking about generation that hasn't really kept up with load. I think the peak load there has grown -- 3.7 is an average. What's peak there, 5.3, 5.4, something like that?

MS. SHEFFRIN: It was 7 percent last year but then very little growth from the year before, so it's been growing, if you average over two years, about 3.7 percent and that's what we're projecting. But all the points you're making are later in my slides.

COMMISSIONER BROWNELL: Okay. Okay. Because I think we want to get to that realistic picture and what we're going to do about that. Great. Thanks.

(Slide.)

MS. SHEFFRIN: Turning to the congestion that occurred in our markets that we were able to resolve in the day-ahead, the largest increase again was on the Palo Verde/Devers line, that generation from the Southwest trying to get into California so congestion on those lines increased. In 2003, they were $3.4 million and then in 2004 they were 27 -- $21.7 million. So this again reflects the large number of imports wanting to get in from the Southwest and they are much more efficient power plants wanting to meet the load in Southern California.

(Slide.)

MS. SHEFFRIN: The next page is the resource addition picture and then after that I'll have the reserve picture that you talked about, Commissioner Brownell.

We saw a high rate of generation addition the last three years, but that slowed tremendously in 2004. So as you can see, where we had 1900, 1700, 2600 megawatts a year of generation additions, we only had 568 in 2004. For this summer, we expect another 1781 megawatts.

In terms of what Commissioner Brownell was talking about, where that new generation located also caused a problem. Most of that new generation came in in Northern

California but the load growth was in Southern California. The other thing that aggravated it is we had much more plant retirements and mothballing. And, again, that happened in Southern California. So I think those two events really exacerbated the supply shortages.

COMMISSIONER BROWNELL: Is this pricing signals? Is it overmitigation? Is it -- you know, people aren't exactly rushing to build in spite of growth, so what's your take on that?

MS. SHEFFRIN: You know, I don't think it's overmitigation because we haven't mitigated prices very much. In fact, our amp procedure didn't kick in on a system level at all since we've had it in place. What I do think is this boom/bust cycle that you see where it really was unexpected amount of load growth in Southern California and so it takes a lag for the generation to keep up. The two things that we have -- you know, that we can hope will help the situation is the resource adequacy requirement that the CPUC will have in place by June of 2006 where all load-serving entities have to meet their peak load plus 15 percent and then also the long-term procurement proceedings which tells the utilities go out and buy 10 years in advance for your requirements -- as much as 10 years in advance. So we're hoping those two things, you know, really spur the investment that we need in the right areas.

COMMISSIONER BROWNELL: There's a lot of people who think that the 10 years really doesn't get you where you need to go, that that is not a sufficient signal. And in spite of those pending kinds of issues, like resource adequacy, we're not -- perhaps you are seeing people line up to build, we're not hearing about that so it will be interesting to see.

Do you think part of it is waiting for market design and some clarity on those kinds of issues and getting some of these major issues settled once and for all?

MS. SHEFFRIN: No doubt there is some of that, but I think the majority of it is people need a contract to go to the bank to finance their power plants. And we're hoping that resource adequacy and long-term procurement helps. You're right, it probably won't help, you know, the full amount. But as we've done in our net revenue analysis for new plants, they can hope to earn part of it without a contract from our markets but they really do need the other part financed partially through long-term contracts. So we're hoping it's a combination of the two revenue streams that gets these plants financed and in the right location, which is Southern California load centers.

CHAIRMAN WOOD: Is there not an obligation on there right -- I'm looking at the dissonance between the amount of retirement you've got in the southern part, almost three gigawatts over this last three years, and then the fact that on the next chart -- which I don't know if it's up yet -- but you've got a need for a load in excess of generation already. If that's not a price signal, why are those plants retiring?

MS. SHEFFRIN: The reason that they're retiring is they're old, they're more than 40 years old, they're not efficient, they're --

CHAIRMAN WOOD: I know but they're all you've got. Is it cheaper to import and pay congestion?

MS. SHEFFRIN: I think that is the case. What we are seeing though is with some of these procurement plans by the utilities, some of those owners -- especially they have wonderful sites right near the load center with all the interconnection facilities. What they're looking to do is, you know, sort of raise the existing plant and build the new efficient combined cycle. So we're hoping through these long-term contracts that that can help stimulate some of that development. I've heard, you know, some plans for it but again I agree with you, we'd like to see a lot more.

CHAIRMAN WOOD: Okay.

(Slide.)

MS. SHEFFRIN: Okay. The next is to get to the difference in reserve margins that you noted, Commissioner Brownell, in our next slide. Even though in 2004 we have

15.3 percent reserve margin overall, it was much tighter in Southern California than it was in Northern California. When you look at those reserve margins by region, we only had a 5 percent reserve margin in Southern California and a 21 percent reserve margin in Northern California. So again, this was a direct result of where the load grew and where the plant retirements and new generation additions took place.

COMMISSIONER BROWNELL: But you agree those Southern California numbers dropped precipitously under any scenario in 2006-2007?

MS. SHEFFRIN: Right. I mean, last year, 2004, was an average weather year, it certainly was not extreme. We only had 5 percent reserve margin. That was the cause for concern and that still is, looking into 2005 summer.

(Slide.)

MS. SHEFFRIN: Okay. Let me now turn to the key market issues that we analyzed in 2004. Four major things happened in the market from the perspective of our department. First, what was the impact for the real-time market software. Let me go to that.

We reviewed the impact of this new software installed in 2004. The purpose of it was to automate the dispatch instructions that occurred in real time.

As you recall, previously, a lot of the instructions -- I'm sorry, I'm on Slide 17.

(Slide.)

CHAIRMAN WOOD: We wanted to talk about 13 and 14, but --

MS. SHEFFRIN: I'm sorry, go ahead.

(Slide.)

MS. SHEFFRIN: You want to talk about 14?

CHAIRMAN WOOD: It's not on there, okay.

MS. SHEFFRIN: It's not on there.

CHAIRMAN WOOD: Did you move it to the back?

MS. SHEFFRIN: Sure, we can talk about that. That's the important aspect of the market fundamentals, which is to track the new generation, whether it can earn sufficient revenues. That's on Slide 14.

A lot of these were common indicators, and so we were told that the Commission already had a copy.

CHAIRMAN WOOD: Oh, no, I mean, I'm concerned about that in light of how the series of questions I've been having -- you know, the price signals that should be sent when you do have a supply and demand coming as close as they are in the market there, but there's not a net revenue sufficiency.

Is --

MS. SHEFFRIN: Again, the net revenue sufficiency is over all hours. A lot of hours, it is more efficient to have the other plants be running; it's more economic. That's where the load-serving entities tend to buy from.

CHAIRMAN WOOD: Does that make us think that maybe there needs to be maybe a more focused approach on the peakers, the ones that aren't going to run 5,000 hours, but are going to run about a hundred?

MS. SHEFFRIN: Right.

CHAIRMAN WOOD: I mean, what would that look like?

MS. SHEFFRIN: Do you want to --

CHAIRMAN WOOD: I mean, what kind of policies do you have or do we need to be thinking about, as the market design reforms hopefully come around the final lap here?

MR. GREG COOK: I'll try and answer that. I think what we've been looking at, particularly when we look at the net revenue, is that it's kind of difficult in California, since we only run an imbalance energy market.

I think that, clearly, no one would build a plant just to sell into an imbalance energy market, so we look at what's the revenue contribution that they could have received through our markets, which is the imbalance energy and the ancillary services.

We did see that for a peaking unit, they would have earned fairly significant revenues in our ancillary service markets, definitely not enough to cover what our estimated fixed cost needs are that they would have. So obviously something needs to be supplemental to that, and what we're looking into now are really looking to the resource adequacy requirements that the CPUC is putting together to provide that revenue, where the utilities would contract with those peaking units to make sure that they remain online, and to recover the fixed costs.

CHAIRMAN WOOD: But until that time comes, we're really at a point here where there's pretty much not an incentive for anybody that's a peaker, to want to come build there, right?

MS. SHEFFRIN: Not sufficient revenues, simply from our markets, but, again, resource adequacy -- right now, the timetable is that it should be in effect by June of 2006, and all load-serving entities have to show the CPUC that they're compliant. We're working very hard to keep to that date, because it is so critical for grid reliability.

MR. GREG COOK: And some of these plants that may -- that we're worried about, may fall, may retire before that time. The ISO is then looking to potentially enter into RMR contracts with those units, to keep them afloat until such utilities are able to contract with them or do so through the resource adequacy requirements.

CHAIRMAN WOOD: Why do the utilities that are -- I guess, most of them are under retail obligation to serve -- not incented to do that today, in advance of June of 2006?

MR. GREG COOK: Part of what we've heard from the utilities is, it's really in our flawed congestion management scheme where, in essence, we -- under our current congestion scheme, energy supplies are considered delivered under contracts, just when they get to the zone.

The real problems we're having with congestion, are within the zones, and actually getting power delivered into the LA Basin on the sub-transmission system. And, unfortunately, we do not currently have a congestion management system that takes that into account, so we have a lot of infeasible schedules, and the way that the markets are working, it's much more -- it's much cheaper to contract with resources outside of those load centers and the have the ISO basically manage the deliverability to get it pulled into the load centers.

CHAIRMAN WOOD: Will that get fixed? I know there's been a debate that, of course, we've followed closely, on liquidated damages versus the physical requirements contracts. Is that going to be fixed if LD contracts are allowed after that point, to fix the intrazonal congestion?

MR. GREG COOK: Yes -- it won't be fixed until we have our new nodal market design put into place. Right now, under the liquidated damages contract, those contracts are deemed delivered, once they deliver they to the zone.

But we found that that does not necessarily mean that they are deliverable, because there may be intrazonal congestion.

CHAIRMAN WOOD: So the zone means one of the three zones in California?

MR. GREG COOK: Right.

CHAIRMAN WOOD: Is that what you mean by "zone"?

MR. GREG COOK: Yes.

CHAIRMAN WOOD: So, really, the large areas.

MS. SHEFFRIN: And not necessarily the load centers, so, you know, it takes some to get it to the load center. What happens with those contracts is that then the burden goes on the ISO to redispatch units to make sure that then the load is met.

CHAIRMAN WOOD: Right. Are those costs over that zone or over the whole state?

MS. SHEFFRIN: Right now, it's uplifted to that zone.

CHAIRMAN WOOD: Okay, so if you get it to SB-15, then everybody in SB-15 is paying for getting it to the ultimate load?

MS. SHEFFRIN: Right. That was the Amendment 60 change, and we'll talk about that in the market issues.

But I think that everyone has noted to the CPUC, concerns about any new liquidated damages contracts, going forward, so that's been noted.

CHAIRMAN WOOD: We're certainly on that, too.

MS. SHEFFRIN: Right.

COMMISSIONER KELLY: Anjalie, when you say the resource adequacy requirements that take effect next summer, do you mean that the resources have to be procured by next summer, and in place?

MS. SHEFFRIN: Yes.

COMMISSIONER KELLY: And are you seeing procurement activities occurring yet?

MS. SHEFFRIN: Yes. When we talk to the utilities -- and there have been many state legislative hearings on this. Each of them are saying, we're fully contracted, we're fully contracted, we have our 115 percent of load, but then, you know, we're concerned, and part of the issue I'm going to cover is, we are running a grid simulation.

If everybody's contracted, we want to see how that's going to be delivered to load, and see if, in fact, all those contracts mean the energy can get to the load in

California.

COMMISSIONER KELLY: Is there a locational requirement in the resource adequacy plan?

MS. SHEFFRIN: There definitely is. We've put a lot of energy to make sure that the power is deliverable and that there is locational requirements.

COMMISSIONER KELLY: And when the utilities are saying that they are fully contracted, are they saying that they are locationally adequate?

MS. SHEFFRIN: I think what they're saying is, as far as they're concerned, they are locationally adequate for the current market design, and, of course, the flaw is, not everything that is accepted day-ahead, can be delivered, and then we have to redispatch it, so, you know --

COMMISSIONER KELLY: So, the current market design has a problem that everyone knows about, but it's not being brought to light? In other words, you might say that you're meeting the resource adequacy requirements, at the same time knowing that it can't be delivered?

MR. GREG COOK: Yes, the CPUC did state last summer that the utilities should take into account, the costs of intrazonal congestion when they looked for contracting for resources for this summer. Talking to Edison, they said that they have, indeed, contracted with more units within the LA Basin, and they listed a number of units where they didn't have contracts last year, that they do this year, so there should be less reliance this year, going forward, on the ISO to actually make sure that their schedules are deliverable.

COMMISSIONER KELLY: And, Anjalie, would you repeat for me, when you said that this was going to be modeled?

MS. SHEFFRIN: I'm sorry?

COMMISSIONER KELLY: Did you say that this was going to be modeled by the ISO soon?

MS. SHEFFRIN: Oh, yes. We're running a peak-day summer assessment, because we are concerned that load can be met when everyone says that they're fully resourced but we're concerned about the deliverability issue. So we are running a simulation this week, and I think your Staff is part of overseeing that simulation, to have everybody, in essence, give us their schedules for an average one- and two-year forecast, and, again, how would they change their schedules and what would be the source of those schedules for a one- and ten-day forecast and much more extreme hot weather.

And then we want to check, is that power deliverable? Where does the congestion occur on the grid? Do we have all of the tools to manage those, if those events arise?

COMMISSIONER KELLY: And you're doing that, and will it be completed by Friday?

MS. SHEFFRIN: It will be completed by Friday in terms of just the simulation, but it will take some more weeks to analyze the results of that, and after we've done that, we certainly will be sharing those with the Commission.

COMMISSIONER KELLY: Thanks.

COMMISSIONER BROWNELL: Have you actually seen the contracts? Have we actually seen the contracts?

MR. HEDERMAN: I haven't seen them. Dan?

MR. LARCAMP: No.

COMMISSIONER BROWNELL: Have you?

MS. SHEFFRIN: I have not seen the specific liquidated damages contract and what their terms and conditions are, but we have explored with some of the parties who have entered into that, what is the obligation? What we've heard is, the obligation is that as long as the power is delivered and accepted in the congestion management scheme that we have, just day-ahead zonal, that that meets their obligation, hence the source of concern and hence running the simulation to see, in fact, if all that power can be delivered to load.

MR. LARCAMP: We do have our folks on the ground that have been sitting in on the simulation, so we should be getting the full report in the next few days.

COMMISSIONER BROWNELL: Okay, good.

(Slide.)

MS. SHEFFRIN: Okay, so covering the four market issues that we analyze, the first one is how well is the new market software operating? The purpose of it was to make sure that the ISO was issuing feasible dispatch instructions. The hope that was once that was fixed, rather than it being done on a manual basis, it would be on an automatic basis; that we put in the generation operation characteristics of each of the units, so we weren't giving dispatch orders that were infeasible, but that would both help increase reliability and operational efficiency.

How did it do? Well, our assessment overall is it started out shaky, as any new large software will, but we've had a shake-out period, it has improved tremendously. There is software tuning going on.

But since the implementation of that first phase of the new market design, which is the real-time market operation software, we did see better operational control in terms of lower CPS violations -- you just heard about the NERC standards, control procedure standards. We saw fewer violations of those. We saw the Cal ISO purchasing less regulation, especially during those high ramp periods that I talked about, 6:00 a.m. and 10:00 p.m. Because it has a two hour look-ahead feature it can get some of those other units ready to be on-line and operating and ramping up so we're not so heavily dependent on the regulation units and moving them, you know, so far above their preferred operating point. So it's a much more balanced operation in terms of which units have to take on that tremendous capability of ramping up and ramping down during those two hour periods -- or time period.

Let's see. What else has happened? A part of the new Phase I(b) was to have uninstructed deviation penalties applied. We have not applied them, but we do show them on the bill. And we think that that's had a tremendous beneficial effect because, you know, people are saying well if I don't change my operation, I could be subject to these penalties.

The reason we haven't put them in effect is we're still trying to iron out some of the communication issues. People are claiming that it's not so easy to put in their outage data to make sure then that they don't get dispatch orders and things. So we're trying to get those ironed out and, after that, making a decision on how best to apply the uninstructed deviation penalties.

In terms of overall price volatility, we have seen increased price volatility. Some of that is to be expected because the program is doing economic dispatch so it is turning units on and then turning them down when it's economic to do so versus the old way, where you were giving, you know, manual instructions. So some of that price volatility is to be expected. The other part of it is again continuing to fine-tune the parameters that go into that software, both on the part of the ISO as well as the market participants will help address some of that price volatility.

The second issue that I'd like to turn to is the real-time congestion costs or the uplift costs that Chairman Wood talked about.

(Slide.)

MS. SHEFFRIN: What we've seen is in 2004 those costs to be $426 million, up from $151 million, so a significant increase. We analyzed the causes of that increase. What we found, that it was due to a number of factors. One is, we did have a large number of transmission D rates last year, so that affected the amount of redispatching that had to occur. And then secondly, the fact that so much energy is having to come in from the Southwest -- not all of it is feasible, but it is accepted in our day-ahead congestion management market, as Greg mentioned.

So again, there's been a lot of things done to address this problem. We have seen these costs decrease in the first quarter of 2005. But, you know, fundamentally the two things that are going to have to happen to deal with this is the significant enhancements in transmission to get rid of those more internal bottlenecks, and I think we've made a significant effort to do that, both getting ready for this year as well as plans for additions over the next few years.

And then secondly, we've got to get this new market redesign which considers the full transmission network in deciding -- in accepting a schedule rather than just some of the, you know, greater congestion points at the zonal level. So I think both of those two problems are going to help address the high level of real-time redispatches and high costs for interzonal congestion.

(Slide.)

MS. SHEFFRIN: The third issue that we looked at is bid insufficiency in our ancillary services market. Again, we noticed this problem really become consistent in 2002 when a large number of these units decided that they couldn't earn enough revenues through the market and turned to the ISO and what we called a Condition II contract, which they're saying look we're not going to operate in the market, do you need us for reliability purposes? If they do, then pay our fixed going-forward costs for the year, but then we won't participate in the market. Well the down side of that is we relied on some of those bids in our ancillary service markets.

The way we've tried to address this problem is two-fold: one of them is previously, before Amendment 60, units that the ISO -- must-offer units that the ISO would put on minimum load, we would pay them for that but they couldn't then bid into the ancillary service market. Part of Amendment 60 last year was to remove that barrier, so if the ISO puts them on minimum load they can still bid in and keep the revenues that they earn from the ancillary service market. That helped improve bid insufficiency, helped improve bids about 12 percent. Not quite enough for us to get rid of all bid insufficiency in our ancillary service markets.

What we're still looking for is some of those contract terms that preclude those Condition II units -- we're paying the full going-forward fixed costs for the year; we'd like for them to participate in our ancillary service market and be able to count on them for ancillary services. But I think it is going to take some contract term changes and, of course, those take longer to renegotiate. But when they come open, we certainly will make an attempt to do that and again help improve the bidding into our ancillary service markets.

(Slide.)

MS. SHEFFRIN: And then finally, the fourth thing that we've all been talking about this morning is the summer outlook for 2005. And again, we expect supplies to be tight particularly in Southern California, I think that's been the theme of my presentation. Under expected conditions one and two, we have adequate resources to meet load and reserves but under extreme hot weather or if some unexpected contingencies occur, we are much tighter, especially in Southern California.

There are a number of actions that have been taken. There's the 2005 state preparedness plan where all the California regulatory agencies have been looking forward to say what can they do to help improve the situation.

We've had some new conservation programs being authorized similar to what got us through the energy crisis: the 20/20 program, which is if you save 20 percent of your energy consumption compared to a year ago, you get a 20 percent credit on your bill. So that was hugely successful during the energy crisis; they brought that program back.

You know, the other thing is we have quite a bit of voluntary load curtailment that's been signed up for, interruptible rates where people have been given rate reductions in turn for interrupting load during high critical time. Unfortunately, on those we have to declare a stage two emergency in order to get access to those. And I have talked to the utilities about our concern about how, if you're going to depend on conservation on the demand side, you shouldn't have to call a stage emergency before you can, you know, get access to it. So again, those are an issue of contract terms; we're hoping that that gets looked into and a better accounting of how conservation and demand side get counted as reserves.

(Slide.)

MS. SHEFFRIN: Finally, if unanticipated conditions occur or if extreme hot weather occurs, we are concerned. That's why we are running a summer peak hour simulation to assess where the bottleneck's going to be, do we have the tools to handle it or not, and try to get a handle on that situation early prior to the beginning of the summer months.

(Slide.)

MS. SHEFFRIN: So finally, in conclusion, I guess I would say that the Cal ISO markets performed well and resulted in stable costs for wholesale electricity, but there are several market issues that we're following, mainly focusing on how the markets will perform this summer but also helping out with the implementation for the long-term market redesign which is going to be critical to, you know, market operation.

CHAIRMAN WOOD: How's the must-offer working? I know that was a critical part of the mitigation in 2001?

MS. SHEFFRIN: The must-offer costs, when I talked about interzonal congestion, and they're rising -- that was a large part of it is the minimum load cost compensation that we paid, must-offer units. I think it's working well but it has been heavily utilized and we really would like to get the utilities to forward contract with these units rather than relying on must-offer to handle the situation.

CHAIRMAN WOOD: Is there some way to make that -- I mean, you know, rather than sign a long-term contract you may never need, if you know that guy has to produce under the -- I think for the country relatively tight mitigation that we have existing in California, what's the incentive for a load-serving entity to actually forward contract as you recommend?

MR. GREG COOK: That's a good question. I think right now, at least prior to there being very direct rules coming from the CPUC directing the utilities to do that, there's not much of an incentive for them to do that. In fact, I think before last summer there was almost, to an extent, a disincentive to do that. There's a certain amount of regulatory risk they have to deal with where they're looking at -- where they're dealing with their procurement plans. They want to show that they did a least-cost energy procurement. These plants that they need to procure with within the load centers are much less efficient so they're much more costly, so you'd have to make more of a showing to show that, yes, these are needed for deliverability reasons. And it's kind of an ambiguous thing to do at this point given our current congestion management system to show that, yeah, we would need to contract with a certain plant and it's worth us to pay, you know, X over market to contract with this plant.

So I think there was a little bit of risk diversion on the side of the utilities where they could go out and, you know, contract with all this new generation coming in from the Southwest at very attractive prices and then they would just leave it up to the ISO to go ahead and commit these units under the must-offer process, given that there's very little if no risk of recovering ISO costs through their rate proceedings.

CHAIRMAN WOOD: I just wonder if there's something we ought to do to the must-offer. I mean, you know, it's great for Arizona to have all the generation but you're going to have this cat fight over who gets to build it. I can just see where that's going. Patrick will be in college by the time that one's built; he's in kindergarten right now.

(Laughter.)

CHAIRMAN WOOD: Getting the locational signal sent to build it in the L.A. basin -- you can certainly build, you know, good clean efficient stuff that is compliant will all the strict air needs that we have to have there. I just wonder if there's something we can do, even in this bridge period, to maybe make the must-offer a little bit less of a guarantee for people who ought to have an incentive to lock something in and take it out of the real-time spot market and move it into the forward market. Because I agree with Anjalie, I mean, if anything we have learned from the California experience in the past five years, it's get in the forward market as much as you can and let the residual market be used to do the ups and downs and, you know, the shaping and all that.

MS. SHEFFRIN: We have noted these concerns at the CPUC and we've said look, must-offer is not going to be here forever, it's to your benefit to plan early rather than, you know, it going away and then you're saying oh my goodness, what can we do about it. So we have been pushing the CPUC; I think they do recognize it and part of the resource adequacy is the locational requirement part and the deliverability part to try to ensure that there is a replacement for must-offer. So I think the CPUC is aware that, you know, they have to do something about that and must-offer is not a guarantee that's going to stay.

CHAIRMAN WOOD: I will say we're penciling in a revisit to California in early June to have a little infrastructure conference out there, not a hugely overly formal one but we have one that we're trying to roll up our sleeves. This might be worth people thinking about, including you-all, Anjalie, and other people in the market, about is there anything prior to the summer peak hitting here that we should think about to encourage, again, some more certainty in the market for both sides of the equation, buyer and seller.

MS. SHEFFRIN: And part of the summer simulation is to see how much is being relied on the must-offer versus them scheduling correctly.

CHAIRMAN WOOD: Right. I think that will help.

COMMISSIONER BROWNELL: I mean, I think we need to be honest with ourselves, which is to say that if markets are in fact working they're attracting investment. And I'd love to think that this last year was an anomaly and not drop-off, but I'm not convinced that it is and I think we really have to examine every aspect that is current to do what California needs to do, which is support its own growth.

I think it's wonderful that the Southwest was able to supply some support, but as we saw in the other cases, their growth is unbelievable, and I don't think they view it as their economic responsibility to continue to support the growth of California at the expense of their own, so I think that we also have to be realistic about what the long-term opportunities are going to be there.

Clearly, the Northwest hydro situation is not getting any better, and whether this is a trend or not, once again, I think we'll see a summer where we're going to have some issues there, as well.

MS. SHEFFRIN: And I think resource adequacy is not only for the state of California, but it's being talked about for the West as whole, and it will help identify if too many people are relying on the same resource, or, in fact, if everybody has adequate supplies to meet their own loads.

COMMISSIONER BROWNELL: I think it's great that people are focused on that. For those of us who arrived four years ago in June, we kind of thought that we'd be further along in the discussion point and into the building point, and that was our first conference that we had there about infrastructure, and we'll look forward to June 2nd.

But I think we need to be honest about our concerns.

MS. SHEFFRIN: I couldn't agree with you more. Thank you.

CHAIRMAN WOOD: Joe, anything?

(No response.)

CHAIRMAN WOOD: Thank you, Anjalie.

SECRETARY SALAS: Let's continue now with the New York ISO.

(Slide.)

MR. PATTON: Good morning. My name is David Patton, and I serve as the Independent Market Advisor for the New York ISO, and performed most of the analyses in the State of the Market Report, so I'll be giving this presentation. Steve Balsar is the head of the Internal Market Monitoring and Performance Unit that's at the New York ISO, so we're both available to answer any questions you have on the performance of New York during 2004.

I'm going to try to move relatively quickly, but feel free to stop me, if you have any questions or if you want to go into anything in a little more detail.

I think I'll -- what I'm going to do is review the performance of the New York markets, in general, and then at the end, provide some comments on significant changes that have been made. A new real-time market has been implemented in early 2005, and I can talk briefly about that, as well as issues that are pending to be addressed in

New York.

The first figure I wanted to show, shows prices, energy prices in 2003 and 2004 in day-ahead markets, monthly in the eastern and western areas in New York. Plotted on here also is the natural gas prices, which is plotted against the right axis there.

And what you can see from this chart, is that the east prices are significantly higher, on average, than prices in the west of New York. This reflects the congestion that we have in eastern New York and the fact that the nodal markets in New York do an effective job of signalling where the congestion is.

I'll show you in a few figures from now, more specifically, where that congestion occurs.

But, secondly, I think you can see fairly clearly that the energy prices in both the east and west, track the movements in natural gas prices, which is what you would expect in a well-functioning energy market.

Most of the marginal cost for the generating units is comprised of fuel costs, and in New York, natural gas and oil resources are on the margin a high percentage of the time, so that movements in natural gas prices should be reflected fairly directly in movements in energy prices.

Where you see a departure from that, is in the summer of 2003. And in the summertime, you do expect the electricity prices to rise, even when natural gas prices are not rising. Largely, this reflects tight conditions during the summer, and periodic shortages of reserves.

In 2004, the reason you don't see that is, we had a very mild summer, with no shortages, so that the prices during the summertime in 2004, basically performed like prices in non-summer periods.

(Slide.)

MR. PATTON: The next figure shows an all-in energy price. Essentially what this is, is the energy price, together with capacity on a per-megawatt hour of load basis.

The capacity values are shown in light blue at the bottom, and then all other costs, including ancillary services and operational costs, are shown at the top of the bar.

One thing that you can see from this, is that the all-in price in New York City is roughly 50 percent higher in 2004 than locations outside of New York City. And that signals really two things:

One is the effectiveness of the nodal pricing market in revealing the value of energy at various locations. New York City is the most constrained location in New York, and areas within New York City.

And secondly, you can see the fairly large difference in the capacity prices in New York City, which is due to the locational requirements.

Once we get to the net revenue analysis, where we show how much money a new generator can make in various locations, you'll see how important it is to have that locational capacity requirement reflected in the capacity market.

One thing I would say is, you can see that there is a dramatic increase in the all-in price from 2002 to the 2003/2004 time period. It's roughly 36 percent higher and it's almost all attributable to natural gas prices, which were significantly higher in the last two years than they had been previously.

(Slide.)

MR. PATTON: The next chart shows you the ratio of the day-ahead prices to the real-time prices. We all get up here and talk about this, but I'm not sure any of us really takes the time to tell you why you should care about the convergence between the day-ahead and real-time prices.

So let me say quickly that the reason that's important, is that most of the power that's bought and sold in spot markets, which would be the day-ahead and the real-time, is transacted in the day-ahead market.

Secondly, the day-ahead market really guides the commitment of generation, so one of the principal reasons you have a day-ahead market, is to rationalize how generators are turned on and turned off, as opposed to a system where you only have a balancing market and it's up to the generators to sort of self-commit their generation.

So it provides a much more efficient means to figure out whether to turn on a unit that is right on the borderline of possibly being economic.

Now, what causes these prices to converge well -- and they have converged relatively well outside of New York City -- largely is the liquidity of the virtual trading markets. Bob will probably talk about that in New England.

It's a fairly important component of all these nodal markets, because the primary means to get the day-ahead market to reflect the prices in real-time, is through virtual traders and the physical participants in the market to come in in the day-ahead, and if the prices look low in the day-ahead, buy more, and if they look high in the day-ahead, buy less, or sell into the day-ahead.

And that then helps rationalize the commitment. Now, what you can see in New York City, is that the convergence is pretty erratic in different locations. What I'm showing you on the right side of this chart, are different load pockets within New York City that are tightly constrained.

One reason why this looks so erratic, is that we don't allow people to submit virtual trades at specific locations. All they can do is put in an offer to buy or sell at the zonal level in New York City, which essentially distributes that purchase or sale throughout New York City, so the fact that Astoria East, for example, on average, the price in the day-ahead market is less than 90 percent of what it is in real time, that would make you strongly want to get in there and buy virtually and sell back in the day-ahead, to arbitrage that, btu they don't have the ability to do that.

One of the recommendations that we've made, is that after a period of evaluation of the real-time market, if this continues, that we allow more disaggregated virtual trading.

COMMISSIONER KELLY: David, why don't we do that now?

MR. PATTON: Largely, New York was one of the first markets to introduce virtual trading, I think, after PJM, and there was a concern that allowing virtual trades at nodes, can introduce gaming potential, because you could select locations where your energy sale or purchase was overloaded at a sensitive transmission facility, you know, immediately, and cause large swings in prices, and that that could be used to engage in games that would result in large payments, if you were an FTR holder or large payments to a generator that happens to be located there.

But we have nodal trading in New England and in PJM, and that hasn't been a significant issue there, so --

CHAIRMAN WOOD: What do you have in mind?

MR. PATTON: Nodal.

CHAIRMAN WOOD: They all have it.

MR. PATTON: They all have it, except for New York.

CHAIRMAN WOOD: Okay.

COMMISSIONER KELLY: And is there a mitigation plan in place in those other areas? Was it deemed to be -- I know those aren't your areas, but likely you know.

Was it deemed to be a significant enough concern that there was a mitigation plan?

MR. PATTON: There is. The difference between PJM and everyplace else is, everyplace else that has the virtual trading, basically, the mitigation is that there's the authority to restrict the quantity of virtual trades that somebody can put in at locations, if they engage in conduct that causes the divergence between the day-ahead and real-time prices, which is what would signal a problem.

To my knowledge, that's only been used once in any market, and you have the ability to ask the person next to me about that.

But it's -- so there is mitigation to address that sort of gaming potential. In PJM, they focused on the FTR dimension of it, and said that if you engage in a virtual trade that creates revenue to your FTR holding, then we can take our money back or we can refuse to pay you under your FTR. I think that probably doesn't address all possible games, but -- and they have actually -- they did actually have a problem with that, which is why they proposed that mitigation measure in the first place.

COMMISSIONER KELLY: Thank you.

(Slide.)

MR. PATTON: The next chart shows you mitigation in the day-ahead market in New York City. This tells you a number of very important things.

In 2004, on May 1st, the prior ConEd mitigation measures were replaced by the Conduct and Impact Mitigation Framework. The ConEd mitigation framework was a fairly simplistic approach that said that when congestion occurs into the City, we're going to cap people's bids at cost.

That sort of mitigation scheme, doesn't require that anyone really have market power, and it also doesn't require that anyone with market power, is actually trying to exercise it. And what that resulted in, for the first few years of the market, was basically mitigation being imposed in every hour of the year in the day-ahead. I think that in 2003, there wasn't a single hour where somebody wasn't being mitigated under that approach.

The difference in the conduct impact framework, is that if your definition of market power is that a generator has the ability to raise prices above competitive levels by withholding generation, you should be able to show that somebody is withholding generation and that they're raising prices, right?

And in these markets, we have the ability to assess that in real time, because we can evaluate the effect of any offer that's made into the market in very short timeframes. So, by applying the conduct and impact mitigation framework, what you can see in this figure, is that, for example, coming into the City, which is the second bar labeled ConEd cable interface, that there was congestion in roughly a third of the hours, so it's relatively frequent, but mitigation occurred in only 11 percent of the hours.

So that suggests that by applying the conduct and impact test, that you greatly reduce the frequency of mitigation, which always has been the primary argument for this framework, that it's much more selective than the alternatives.

And it presents interference in the market when it is not warranted.

(Slide.)

MR. PATTON: Okay. The next chart is the net revenue from the New York markets. And what the three sections of every bar you're looking at show you is the capacity -- the net revenue attributable to capacity on the bottom, then energy, and then ancillary services. It shows here new combined cycle resource on the left and a new combustion turbine on the right at three locations. The capitol zone happens to be in Eastern New York, upstate.

So what you can see from this chart is if you remember on the all-in energy price chart, energy was the dominant component of the price and capacity was relatively small. When you look at net revenue, capacity becomes much more important. Because what you're measuring with net revenue is the profit that a generator is earning over its variable cost when it runs, and when it earns $50 in the energy market, $40 of that may be variable costs so you lose a lot of your net revenue from energy but the marginal cost of supplying capacity is close to zero so all the capacity translates into net revenue.

And what you can see from this is how important the net revenue, particularly in New York City, is. While our conclusion is that in 2004 a new unit is marginally not economic in any -- it's not close to being economic in the capital zone, and that's because there's a surplus upstate, so that shouldn't bother you too much.

New York City, though, is much tighter and the net revenue is not quite sufficient in 2004. But had we not had locational capacity requirements, we would be in deep trouble in New York City. In fact, you'd have probably most units in New York City in here wanting RMR contracts from you. But the locational capacity requirement in New York pretty much solved that problem. It allows the existing generators the funds they need to maintain their generation and new generators to site.

Largely the reason that the revenues hasn't been sufficient in New York City in 2004 is that two components you need to motivate new investment is high prices during periods when you're reserve-short -- which is what we call those shortage periods, even though you're not turning anyone's lights off. And New York has the most comprehensive market design to address that with the reserve demand curves that automatically set prices at the value of the reliability you're losing when you have to compromise your reserves. The problem was this was a very mild year so that never kicked in in 2004, unfortunately, or you could see the -- or you would see the impact of that. So the shortage pricing and capacity are the two components.

And if you expect people to build, you need to see that these net revenue values exceed what it costs somebody to build. Because nobody's going to go out and sign a long-term contract -- a buyer in a long-term contract is not going to pay more than what you see on this chart if they're smart, unless they have a regulator forcing them to sign a long-term contract and build some kind of premium into it.

So if you're looking at a market with perpetual net revenue that's too low and you're short of capacity, then you've got a market design problem.

CHAIRMAN WOOD: And so when the demand curves kick in, what does that show here? Which color --

MR. PATTON: The energy line would get bigger.

CHAIRMAN WOOD: The energy line gets bigger because the energy costs would be set by the formula at that stage when you get -- and again it's triggered by a reserve margin that gets lower than seven or whatever the number is -- or 18, I think. It ramps down, right?

MR. PATTON: Yeah, it phases but when you're short of 30-minute reserves, you'd see roughly $200 a megawatt-hour increase in energy prices. And when you start getting short of 10-minute reserves, then prices can go up over $1000.

CHAIRMAN WOOD: And the reason that that is done as opposed to just letting that be a market-drive price is what? Remind me.

MR. PATTON: That the generators can't, by themselves, cause the prices to reflect the lost reliability. What happens when you go into a shortage is you're holding out, let's say, a thousand megawatts of generation and you're holding that out to maintain reliability and when -- when load is increasing and you need more supply, you'll start marching up the supply curve. But when you get to -- when you start getting to a relatively high point on the supply curve, it's also the point where it looks like the lights may go out someplace and so the operator presses the magic button and some of this thousand megawatts of reserves comes into the market and that moves you down the supply curve then so you can be looking at a hundred dollar price when you've just compromised your reserves.

Now the reason you know the hundred dollar price is wrong is that had we had a choice of a thousand dollar per megawatt-hour import or, you know, some source of thousand dollar energy, the market software would have said I'll take it and set the price at a thousand dollars in order to maintain my reserves. I only release my reserves as a last-ditch effort or when I have to. So unless you attach a value to what you've just done --

CHAIRMAN WOOD: Got it.

MR. PATTON: -- then you defeat the whole shortage pricing problem -- or shortage pricing -- the ability to have shortage prices that are efficient.

Now we've experimented by saying, you know, maybe we can just not mitigate generators. And the problem is that there's no way of getting -- of having generators that just offer at high prices get you high prices when you're actually short and not when you're not short, so it tends to be unreliable. So hopefully once we get to the point where we have a normal summer in New York, you'll actually see more of how this works and I think it's fairly important.

The other dimension that is difficult in every market -- just set this in the back of your mind as something that has to be fixed -- is allowing peaking units to set prices when the marginal source of supply. They sort of operate on a time frame that's not convenient for a five-minute dispatch; you know, they turn on every 15 minutes.

CHAIRMAN WOOD: Right.

MR. PATTON: You can't really treat them as on-line energy like you do a steam unit. So when they're the marginal source of supply, it's really hard to get them on-line and setting the price when they should be setting the price, so that creates some problems. And New York has invested quite a bit in software improvements to try to handle that, but as far as I know they're quite a bit further along than most other markets. I certainly would like to have their software in the Midwest.

COMMISSIONER BROWNELL: Why don't you?

MR. PATTON: Different vendor.

But it's something that I've talked to participants about. They're running lots of peakers in the Midwest that aren't setting prices and it's creating significant problems.

CHAIRMAN WOOD: Wait, wait, wait, wait.

(Laughter.)

CHAIRMAN WOOD: And that's because the software can't do -- tell me how the New York software is superior to that?

MR. PATTON: The New York software is superior to that because they have -- when they run their real-time market, they're essentially running two different markets. They run one pass that treats the gas turbines as if they were flexible and on-line and says okay if, with infinite flexibility, we would take this set of gas turbines anyway, then they set the price in -- the nodal prices. But when they do the physical dispatch and actually send signals to generators, they recognize that the gas turbines are very fairly inflexible, they take a while to turn on, once they're on you don't want to turn them off because you won't be able to turn them back on. They can only operate very close to their maximum level so they don't have a dispatch range like a normal steam unit.

Most markets, basically the pricing and the physical dispatch are identical to one another so that when you're faced with this inflexible gas turbine, it prevents that gas turbine from setting the price so you end up setting the price by some much more flexible steam unit, which might be a hundred dollars cheaper. There's no way of knowing unless you do the secondary test that that gas turbine energy is really economic.

CHAIRMAN WOOD: So having a two-track -- having one set the market price, which would be what works, which is what they do in both markets, but what the New York's does in addition to MISOs is it, on the scheduling basis, actually looks at the feasibility -- looks at the physical constraints that exist.

MR. PATTON: Yeah, and the terminology you would recognize from New York in terms of the filings that were made to implement this, was hybrid pricing for gas turbines. So that was, you know, a couple of years ago that -- maybe three years ago that they recognized that as an issue and worked on the software.

MR. LARCAMP: I understand though that the CT issue in the Midwest is not exclusively the result of software problems but there are many other facets that the market participants are looking at right now, such as maintenance and the fact that people may have been bidding units in incorrectly and a host of other things, is that not an accurate representation? I don't want to leave the impression that the software is the primary problem with the overreliance on the CTs right now.

MR. PATTON: Those are contributing factors. Those factors, I think, contribute to how many peakers are running. But I think -- I don't project that they're going to stop running peakers, even if they resolve all those factors, largely because once you get on the peakers if they're not setting the price you're not going to get imports over the roughly 23 interfaces into MISO and you're not going to be setting prices that cause people to buy more in the day-ahead market and commit more generation so it's sort of an issue that sustains itself. Where if they were setting prices, you'd get more imports from outside and then you could turn them off. So yeah, it's complex and those factors are all contributing factors.

MR. LARCAMP: I guess, given the fact that we've, from experience on Staff, learned that effectuating software changes both is time-consuming, upsetting the market participants and pretty expensive, that before we start looking at software fixes we might want to make sure that all of the market participants are playing by the current market rules and software -- maybe simultaneously at least while we're looking at the next generation of software.

MR. PATTON: Yes, that's certainly true.

CHAIRMAN WOOD: One item, to just follow-up on that, that came up. I was at NERC yesterday and saw Jim Torgerson. You know, a number of the CTs are not bidding their minimum cost and so they're going to be at the front of the line on the dispatch when in fact they could easily have stayed in the parameters that are permitted under the current software to say it's going to cost me this much to ramp up, this much to keep that minimum run, and that those costs actually would have changed their place in the dispatch.

MR. LARCAMP: And I know that David and his folks have been having discussions with them making sure that they understand how the reference prices work. Apparently a lot of people were not living in the day of the life; well, day of the life was going on for almost a year in terms of understanding how the market rules were going to work.

CHAIRMAN WOOD: I heard the same thing at the southwest power pool last week when everybody was ready to go to the imbalance market to save a billion two dollars over the next decade and some people didn't actually get ready for it and thought it wasn't going to be a big deal.

MR. LARCAMP: Staff obviously is looking at this and we're looking at it both from a commercial issue but we're also looking at it because the peakers can only run so long under their mission permits, and there are also issues with respect to maintenance: after they run so many hours, they have to be taken down for maintenance. So we're looking at this not only for a current cost but also for later in the summer. So I can tell you that our two folks at MISO are on top of this issue.

CHAIRMAN WOOD: Thank you. All right. Back to the Empire State.

(Slide.)

MR. PATTON: Okay. The next figure shows you monthly congestion costs from 2002 to 2004. You'll see that it rose significantly in 2002, from 2002 to 2003. That's largely due to the implementation of the modeling of transmission within New York City which previously hadn't been reflected in the nodal prices. And that congestion is among the most significant. It's in New York, so it results in an increase in the total value of congestion.

CHAIRMAN WOOD: Is congestion -- I'm sorry. You'll have the answer to that.

MR. PATTON: Let me tell you what this is, because there's a lot of confusion I think on what people mean when they say congestion costs or the value of congestion. What I'm showing you on this chart, which totals over $600 million in 2004, is the marginal value of congestion.

It also is equal to the congestion rent collected by ISO and then paid out to holders of transmission rights. Now, this is not the benefit of eliminating the congestion, which has been estimated to be less than 100 million.

And so when you start thinking about should transmission investment be motivated by the costs that we see here, if you're talking about very small-scale investment, then the marginal value of the transmission is probably accurate.

If you're talking about siting a big line that's going to wipe out congestion into New York City, the value you get from that is much lower than this.

The --

COMMISSIONER KELLY: David, why is that?

MR. PATTON: Think of it like generation. We set a market clearing price, which is the marginal cost of the last unit of generation that we dispatch, let's say, $100.

If I flood the market with generation, I don't save $100 for every megawatt of generation, or if I'm able to cut load to zero -- that's at better analogy -- I don't save $100 for every megawatt hour that I don't dispatch; I save $100 for the most expensive generator, and then I save less and less an less and less.

It's the same thing with transmission. If I incrementally increase the interface capability, I do save the difference in price between the two locations, but then the difference gets smaller, and if I keep expanding, the difference gets smaller and smaller and smaller.

And it's the -- and the difference that you save at every step, is really the efficiency; you know, it's the cheaper generator over there that now can be delivered and displace the more expensive generator over here.

So that's --

COMMISSIONER KELLY: Is that how you go about estimating the benefit?

MR. PATTON: Of transmission investment? Yes. The nice thing about the nodal markets is that it does send an accurate price signal for investment, but the place where it has trouble, is if you're talking about economies of scale where the most efficient investment is a big, new DC line.

If you're talking about incremental investment and, in my experience, most of the investment we're talking about, really is incremental, although most people think of the big, high-voltage line, most of the time, if you asked a utility, tell me how we can increase the capability between here and there over the next three or four years, they would be upgrading a transformer and re-conducting a line and doing incremental steps, each of which removes one limitation and increases the capability by some increment, rather that siting a whole new line.

And for those sorts of investments, the nodal pricing works well and sends the right signal.

When you have economies of scale, where the congestion is just going to be wiped out, then the value of the transmission rights you would get after the investment, that's how you would, in a market context, you would pay people to build, is to give you transmission rights if you expand the system.

The value of those rights is going to be very low. So that's really where if that's the best option, that's really where planning has to kick in and say, well, we know this -- we know what you would normally get for this investment wouldn't be compensatory, but it's still the best investment, and it's clearly more economic than generation and other transmission investments, therefore, we're going to give you a rate of return on it.

But in my opinion, that's what you should -- you should limit the rate and giving people embedded costs compensation for investment to that sort of situation.

(Slide.)

MR. PATTON: All right, let's go to the next chart, where I show you how this breaks down between upstate and downstate New York. What this figures shows you is upstate on the left and downstate on the right.

In 2004, the downstate congestion, which is congestion into New York City, within New York City, and into Long Island, is roughly five times larger than the upstate congestion.

This is notable because the Central East constraint at the start of the market, had been -- had generated a sizeable amount of congestion. That's what separates western New York from eastern New York.

But over time, the congestion has decreased on an interface, because of investments in eastern New York. We've had some big combined-cycle plants site investment in New England, so we're getting more power in from New England, which relieves the need to go from west to east, and decreased imports from Hydro Quebec, who happen to bring power in right on top of the constraint, and so they aggravate it, and they're bringing in less power than they had historically.

So, for all of those reasons, the upstate congestion is diminishing, although the downstate congestion is still significant, particularly within New York City.

(Slide.)

MR. PATTON: I'm going to skip this figure and go to the next one.

(Slide.)

MR. PATTON: The next one shows you uplift costs.

DAM uplift is day-ahead market. That's all the way on the right.

Then there's real-time local reliability uplift and other real-time uplift. Real-time local reliability uplift is essentially when you have a constraint in some local area that is not reflected in your market, so you're taking actions-out-of-merit to try to resolve it, either turning on a generator or redispatching a generator.

The day-ahead uplift, which has increased -- the reason that there's day-ahead uplift in New York is, we try to resolve a lot of the local reliability issues in the day-ahead market, as opposed to PJM and New York and the Midwest ISO, which have a reliability commitment process after the day-ahead market. New York builds it into their day-ahead market.

And because prices were low in 2004, because of the mild weather, we tended to have to pay more uplift when we had to bring somebody on to meet a local reliability requirement, out of the economic order.

So the higher prices are the more of the cost that are going to be compensated through the market and the less you have to pay in uplift. So that's the main reason why the uplift increased in 2004.

(Slide.)

MR. PATTON: Going to the next chart, this is very difficult to see, but let me just tell you that this is a continuing analysis in a series of analyses on how well the interfaces between New York and adjacent markets work.

The panel you see on your left, is the same plot that we've been showing for years, which shows the difference in price between New York and New England. In our report, we do this for all the interfaces, but the difference in prices between New York and New England, and then the flow between New York and New England on the X-axis.

And basically, the upper right quadrant and the bottom left quadrant, are points or hours when power is flowing from the higher-priced market to the lower-priced market. We call them counterintuitive quadrants.

The average difference in price in any particular hour, ignoring the sign, is shown on the right in the bars between New York and New England, and is roughly $10 a megawatt hour.

What you can conclude from this analysis, is that in real time, we're not utilizing the interfaces terribly efficiently; that participants have a difficult time arbitraging price differences between the two markets.

This excludes situations where the interface is constrained and you really can't ship more than you are.

CHAIRMAN WOOD: When did the right pancake disappear? Wasn't it toward the end of the year?

MR. PATTON: Yeah, at the very end of the year, so it wouldn't be reflected in this.

CHAIRMAN WOOD: So, do you think -- can you tell from any initial 05 data, if that's a problem there that should be pointed out in this chart, has been remedied by the elimination of the pancake?

MR. PATTON: We think it's getting better, but it's hard to tell, without looking at a fairly wide timeframe.

CHAIRMAN WOOD: You've got to look at the year.

MR. PATTON: But what we should see is that the $10 number goes down somewhat, because small price differences should be more attractive to arbitrage than they used to be, due to the export fee being eliminated.

The large price differences that you see in the scatter plot, that can often be $50 or $100, really, probably wasn't affected by the export fees as much as by the uncertainty in the other factors that made it difficult for participants to arbitrage the price differences.

CHAIRMAN WOOD: But it looks like it's roughly twos-way traffic there, though, right?

MR. PATTON: It is, yes. New England and New York is one interface where the power can really go in either direction, depending on the situation. They have similar costs in terms of their resources, where, for instance, the PJM interface tends to go in our direction, in the New York direction more often.

But these results suggest that it still would be valuable to have the ISOs explicitly coordinate their physical interchange, which we have affectionately called by different names. It's changed names again, but it was virtual regional dispatch, VRD, and I think that now it's called inter-hour scheduling.

We still think it's a good idea; we still think that participants will never have full information on what the most efficient thing to do is in real time, and that implementing a coordinated dispatch between the areas, does nothing more than manage the interface the way we manage the internal interfaces inside of our markets, where it's the offers of the generators and the bids of the loads that determines what flows.

COMMISSIONER BROWNELL: David, we've talked about that under various names for awhile. What is impeding the resolution of that?

MR. PATTON: Basically lack of participant support. The participants who should like it, are lukewarm and may not understand the importance of it.

The load-serving entities should all love it, because under our shortage pricing methodology, the reserve shortages, it's just a matter of time till we set $1,000 prices in New York when we have unused interface capability, and then they're going to say, oh, my god, we weren't -- why were we paying $1,000, and then I'll say, because we don't have a system that allows us to fully utilize our interfaces.

Then they will say, we should do VRD, but we haven't had shortages in New York, so the economic incentive hasn't been staring them in the face.

There are people who benefit from not having it, and they tend to be the more vocal. The marketing community likes having the interface, I think.

My hypothesis is that it's attractive to them to have an interface that's not well arbitraged, because they then can make some money arbitraging it, and for the same reason that the load should like it, the generators probably shouldn't like it, because, you know, they might benefit sometimes from higher prices due to inefficient use of the interface.

So, basically, it hasn't made it through the governance process, but we did just finish a pilot project between New York and New England, where they explored -- they had a period of time where they adjusted the interchange according to the instructions of the ISO, so it wasn't done economically, but it was just done to see

whether we could adjust the flow every 15 minutes and
whether that would -- what that would do to the prices.

Now you'll remember that PJM and MISO were dating somewhat on the region and I think the next step for those two is to coordinate on the interchange, and I think once they do that that will be a fairly good model that we can say this really should be done elsewhere. But I continue to think it would probably take -- would be something that takes some pushing by the Commission to get it to happen.

COMMISSIONER BROWNELL: Maybe this is a topic we can add to the agenda at the regional RTO meeting next week chaired by Mr. Flynn, because I think these are the very issues he would like to discuss and the other state commissioners would like to discuss. We should pursue that.

MR. PATTON: Why don't I just skip over the ancillary services figure and go just straight to a quick note.

(Slide.)

MR. PATTON: We've implemented new real-time markets in February of 2005. It basically has a much better system of scheduling external transactions and inflexible resources on a 15-minute basis and has a dispatch model that runs on a 5-minute basis that looks a lot more like the day-ahead model. We think it's going to resolve some modeling inconsistencies between the day-ahead and real-time that had previously occurred and that we talk about in our report. And we're going to be evaluating the performance of that market after this summer. It also includes the reserve demand curves that we talked about.

(Slide.)

MR. PATTON: Lastly, I'll just say one note is that in all the markets supplemental commitments that have to be made for local reliability reasons continue to be something that affects the outcomes of the markets in New York, it's the NOX regulations in New York City that cause a significant amount of commitments to have to be made out of the market process. So the report recommends improvement be made in the software to try to explicitly model some of those environmental requirements.

And that's all.

CHAIRMAN WOOD: David, thank you as always. We've peppered you throughout.

SECRETARY SALAS: Okay. And now the New England ISO.

MR. ETHIER: Good afternoon. Thanks for the opportunity to talk about the New England markets. It's very helpful to follow David because a lot of the high-level messages are going to be very similar in New England as they were in New York. And as sort of a procedural item, I have a heck of a lot of slides here. I'm going to skip through some of them, certainly please stop me if there are ones I skip over, and I'll try to cover about half a dozen of the

30-plus that you have.

(Slide.)

MR. ETHIER: Slide two, overview of 2004. The New England energy markets continued to function well in 2004. They operated as designed, there were no significant exercises of market power in 2004, so that's clearly a good message to be able to bring here today.

New England, just like New York, was characterized by low summer loads in the summer of 2004. Our summer peak was actually 2.3 percent lower than the preceding year, and that, in turn, was lower than the summer peak in 2002, so we've really had two years in a row of relatively cool weather in New England.

Our projected peak for this coming summer is about 2000 megawatts higher than what we experienced in 2004, so fortunately the outlook is good, we should have adequate capacity to meet that in the upcoming summer should we hit that peak. Things will be a little tight in the load pockets of Connecticut and of Boston, which is also a familiar theme here, but it looks like things are going to be fine.

Again, we had a surplus of generation region-wide. We've been in this situation for a couple of years. And that basically is -- those two sort of factors make the market results look very sensible. We had competitive market results and there were really no strong incentives to build new capacity in New England, which is what you'd expect -- we have a peak summer load forecast of this summer of 26,000 and we have summer-installed capability of 31-, 32,000 megawatts. So it's not so surprising that the markets are not, on a region-wide basis, signaling the need for new investment. We do have some areas of New England that do need investment sooner than that.

CHAIRMAN WOOD: We know them well.

COMMISSIONER BROWNELL: Several years ago, actually.

MR. ETHIER: Well, yes. Next slide.

(Slide.)

MR. ETHIER: New England has now operated markets for a full five years now. We began operating markets in May of '99. This is our fifth full year, 2004 was, and it seemed like an appropriate time to sort of step back a little bit and see sort of what has happened over that time at a high level. And, you know, in my view there have been some notable improvements over that time period.

We've had approximately 9500 megawatts of new efficient gas-fired generation built over that timeline. The average heat rate of liquid fuel resources has decreased by 5.6 percent. We've had unit availability increases over that time period of roughly 7 percent on average.

That number is interesting because if you go back pre-market, the difference looks even bigger. So in the mid-90s we were seeing availability in the mid-70 percent range and it's jumped up to the mid-80 percent range. So that -- you know, I think at least part of the explanation there is the improved incentives for availability under the market system, which is certainly good news. Fuel-adjusted spot prices, consistent with the decline in heat rates, have decreased by 5.7 percent over the time period, and it's important to note that because that's often masked by the world we're living in now with extremely high liquid fuel prices.

And everybody points to the high prices and has questions, but you know when natural gas and oil prices are such a huge driver of the incremental costs of these resources, it's not surprising that electricity market prices have gone up. It's important to do the analysis to understand that the underlying costs have actually decreased if you normalize fuel prices. So if you strip out the fuel price changes, things look quite different. And for example, improvements in our regulation units' performance have reduced requirements in that market by 29 percent.

So, you know, sort of on this sort of anniversary, if you will, it seemed reasonable to go back and take a look at sort of where we've made some progress.

The biggest change in 2004 was the introduction of a forward reserve market. We ran our first auction in December of 2003, beginning, I believe, January 1 of 2004, and I think that's been successful in introducing incremental investment as well. We've seen some very specific actions by participants in response to the incentives provided in the forward reserve market and those actions have worked to increase the quick start resources in New England, which we really don't have enough of. Probably in equilibrium we should have another thousand megawatts of quick start resources, and we don't have those resources. But we've gotten more in part -- and more reliable resources in part because of this market.

For example, we had a unit that signed a firm gas contract so they could reliably provide reserves in the winter-time. We had a unit add dual fuel capability so that they could also more reliably provide reserves. And we actually had an inefficient combined-cycle resource that was sort of an older design that wasn't making money in the energy market say well I'm better off offering as two separate combustion turbines in the forward-reserve market than sitting on the sidelines of the energy market 80 percent of the time.

So those are the sort of responses that the market has induced, which to me are the right kinds of incremental responses. You know, we haven't seen the sort of big bang 200 new megawatts of peaking resources, but you've seen these incremental investments and market responses that get you what you need.

And this sort of dovetails I think with David's response about transmission investment. Oftentimes it's the sort of, the small incremental investments that can make a big difference, it doesn't have to be the big bang $500 million investment that's required to resolve your problems. And that's the nice thing about these market signals is they send signals to everybody to make big and small investments alike.

CHAIRMAN WOOD: Do the TOs have the incentive to respond, even in ISO New England? Do they have the incentive to respond to those if they're not the beneficiary of making that investment, or their holding company is not the beneficiary?

MR. ETHIER: Well I think that's an area where, going forward we definitely have to keep working on that. I think the nice thing about the markets is they provide signals where investment is needed, but the connection between those signals and the TO response isn't as strong as probably we would all like because they live in a different regulatory world. And that's part of, frankly, our responsibility as market monitors to highlight those sort of deltas and focus a spotlight on where we need investment and why the market signals may not be getting to the entity who's best positioned to resolve that.

In New England, we're sort of working through what we hope are sort of the last big changes in our market design, and I can easily see the connection to the transmission investment making that tighter, being sort of the next wave of our efforts to make the markets work better.

Let's go to the next slide.

(Slide.)

MR. ETHIER: 2004 was not without excitement in New England. As you all know, we experienced exceedingly cold weather in January of 2004, and it stressed the New England energy infrastructure, and by that I mean both the electricity and the gas systems were highly stressed.

It really brought out some issues that needed to be improved in the operation of those two systems or the coordination of those two systems.

As a result of that experience and of the analysis that we did, the ISO implemented basically 29 different recommendations to improve the operation of the markets under similar circumstances.

Just to highlight a few of those, some of the biggest ones are: Improved information exchange between the ISO and the gas pipelines. We now have a much better handle on how the pipelines are operating, what their limits are, et cetera, and what generators are more likely to be able to get gas and operate, and also improve the information exchange with our participants, so that they have a better sense of the critical nature of systems on our system, so that they could be prepared that market prices might go up, for example, or that they may be called upon to run to support reliability.

We have gained some additional dual-fuel operating flexibility, which is probably some of the low-hanging fruit here in terms of getting real additional capacity. We have plenty of installed capacity in the wintertime in New England, but peak load last winter was roughly 22,000 megawatts, and in winter capability, we have 33,000 megawatts, so we have ample iron in the ground, if you will. The real trick is getting the fuel to those resources when you need it.

And that's why the dual-fuel capability is so important, because when the gas pipelines are constrained a handful of days a year, it's really helpful to have all that capacity to be able to operate on oil.

Then, finally, under the most extreme conditions, we have a temporary solution to adjust the market timeline so that the electricity market better coordinates with the gas market, and so that we can, importantly, most fully utilize the gas infrastructure in New England.

One of the things that we saw last winter was, while we used the gas infrastructure pretty well, we didn't fully utilize the pipelines coming into New England, and it's key under the most stressed situations, that you take advantage of every possible Mmbtu that can be brought into New England.

One of the impediments there that we saw and still see, is the timing of the electricity market. And so we have a short-run solution that's in place for a couple of years to help resolve that, and, in the longer run, we're looking at some more far-reaching --

CHAIRMAN WOOD: Is that a New England solution or is through the NAESB process?

MR. ETHIER: I think some of these issues, especially the communications improvements that we've come up with, are going through the NAESB process. I'm not aware that they are considering the market timing issues as carefully, in part because that's a complicated problem; it really is, you know, and, in part because we feel it most acutely.

We're sort of having to figure it out as we go along. I would hope that if we come up with something that works, that that can be distributed more widely.

Okay, there is some ongoing work from what we experienced in January. In January 2004, during the cold snap period, LMPs did not accurately reflect the cost of the most expensive needed resources on the system, and we took a look at 2005, and things are much improved in that regard.

The caveat, of course, is that it wasn't as cold in 2005, so you might not see these problems. But it's also likely that the communications and the forecasting improvements have helped improve that as well.

If you have more certainty about what units are going to be around, you are able to dispatch your system in a more consistent way, rather than if you have a great deal of uncertainty about units, whether they are going to be available to operate, the level of reserves you may need to carry, may increase.

So that's been good, and the other ongoing issue that we're looking at is the need for increased availability incentives, so that the 33,000 megawatts that we have, actually can run when we need it to run. That strikes me as critically important.

Okay, next slide.

(Slide.)

MR. ETHIER: There are a couple of big challenges, moving forward. A big one is daily out-of-merit operations. Those costs have gone up again, for a variety of reasons.

And the ISO is working -- and this gets back to your earlier question about are the TOs responding in a timely manner to the signals that are out there. I think we have some evidence that they are.

We do have very targeted upgrades that will solve specific problems that lead to uplift, however, you know, there's always room for improvement in that area.

And then the other area that we're looking at is unit flexibility. We have -- a lot of the new combined-cycles -- it may be safe to say that all of the new combined-cycles have relatively high economic minimum limits, relative to their economic maximum limits, and they're big units and they have long run times.

So if you have to commit one of those resources to resolve a transmission problem, it costs a lot more than if you have to commit a small resource. So, what we're looking at are rule improvements of software improvements that allow us to better model combined-cycles in a flexible ways; that is, a combined-cycle can say, well, I'm willing to run one of my GTUs instead of two, as long as I'm comfortable that I'm going to get fully compensated for the start costs in the second GT, et cetera.

I think that would help reduce uplift costs; it would also help to reduce the out-of-merit problem -- sorry, the out-of-merit impact on reducing LMPs, and so there are a lot of good things that could come out of that, and that's one of the important things that we're working on.

And, of course, we still need additional quick-start units in constrained areas, and we are exploring with our stakeholders, a locational forward reserve market to better incent quick-start capability, not just poolwide, but especially in Connecticut and in NEMA, where we really need it the most. That will also work to reduce uplift.

CHAIRMAN WOOD: But what would the product there be?

MR. ETHIER: It would be very similar to our current forward reserve market, but instead of having all megawatts in the pool being equal, you'd have constraints, you'd have requirements in Connecticut and requirements in Boston, and then requirements in the rest of pool, and likely what would happen, would be that the prices in Boston and Connecticut would be higher, because we have a shortage of quick-start capability in those areas, and that would provide stronger incentives in those two areas for quick-start capability.

CHAIRMAN WOOD: Okay.

MR. ETHIER: And then the other sort of big challenge, which you all are also well aware of, is the increase in reliability agreements we've seen over the last year. It's really been dramatic, yes.

Right now, we have about 2200 megawatts under agreement, with another roughly 4600 megawatts actively seeking reliability agreements. That's about 20 percent of the pool, which is never how any of us intended this to sort of play out in New England.

And that just, to me, points out the need for a long-term resource adequacy solution, because these agreements send no really useful incentives to existing units, or to potential new entrants to enter the market and resolve our problems. They're really just sort of a holding pattern.

CHAIRMAN WOOD: And by "long-term," is this the LICAP proposal that's now before the Commission?

(Slide.)

MR. ETHIER: That's right, that's right. Okay, if we can move along to Slide 14, which is sort just a pictorial representation of the congestion that we see in New England, it comes out a lot better in color than in black and white, so I hope you all have color.

What these maps of New England do, is show you the average prices throughout New England in both the day-ahead and the real-time markets. And the important thing is, we also put them on the same scale, so that you can see differences, not only intra-New England, but also differences across the day-ahead and the real-time markets.

And, you know, there are sort of three things that I would highlight here. One is that Maine is relatively inexpensive, consistent with lots of generation and export constraints.

Connecticut has the greatest concentration of red, which means the highest prices. What I would also point out is that this is a combination of congestion and losses driving these price differences.

And losses are non-trivial. The difference in losses from Maine to Connecticut in an hour, can easily be $10 to $15 a megawatt hour, so there are very big impacts from losses.

And then the other thing that you'll notice on there, other than the low prices in Maine and high prices in Connecticut, is that NEMA Boston looks a lot like everywhere else.

And that's largely because of the large amount of out-of-merit that we have to commit, I believe. If we had more quick-start resources in Boston, we would see more constraints and there would be more price separation in the Boston area, but, in part because of the out-of-merit actions we have to take, it serves to basically keep the LMPs in Boston, more consistent with the rest of the pool.

Probably the next slide we should go to is slide 24.

(Slide.)

MR. ETHIER: And in some ways this is one of the more troubling slides that I have and it looks sort of innocuous initially. But this is the total number of megawatts we have enrolled in our demand response programs by month over the last two-plus years. And I'll admit I cheated a little bit and added a little bit on to the end so we'd go into 2005 with this.

But basically from roughly June of '03 through approximately this April, our demand response enrollment's been pretty flat. It's been right around 350 megawatts. In the long run, that's not going to be enough. I firmly believe that an active and vibrant and deep demand-side sector is important for these markets to work well, and we've sort of stalled in New England.

And I don't, you know, sort of mean to imply it's the fault of the folks who are working on it at the ISO. It's really a combination of two things, I think: incentives are relatively low right now in part because the capacity market is paying very low dollar amounts. So there's just not as much money in this program as there has been historically.

And the other one is New England's, you know, sort of the next step in demand response is working really closely with the states to improve the retail rate design, so that retail customers see something that looks a lot more like real-time pricing. And whether we'd go all the way to five-minute prices or not, I don't know, but until we get the residential and the commercial customers to see the prices, I despair that we're not going to see the level of demand response that we really need to have vibrant response in these markets.

So it really hit me, this is, you know, sort of -- you sort of feel like you live through these markets, you know what's going on, but then when I saw this graph, it really struck me that we really haven't made any progress on this in a couple of years and that's disconcerting.

Okay. Let's go to slide 29 next and then we'll go to the conclusion.

(Slide.)

MR. ETHIER: Really briefly I mentioned in the first couple slides that New England would not support a new resource in 2004, and that's sort of what these numbers show. If you look at the middle bold columns in both the combustion turbine table and the combined cycle table, the bottom row there shows the estimated net revenues in the New England markets for each of those resources for 2004. Combustion turbine would have earned about $52,000 a megawatt-year, which is a big increase over 2003 and that's driven almost entirely by the forward reserve market. So there are some real signals being sent by the forward reserve market to maintain your existing resources and get some incremental quick-start capability. But again, if you look against the two right-hand columns for the estimated fixed cost range for these resources, they're still not -- we're still not at levels that would incent a new unit.

And the story is sort of the same for the combined cycle with the absence of the forward reserve revenues, because they can't really provide forward reserve products economically. Combined cycle would have earned slightly more than half of its estimated annual fixed costs in 2004. And again, those are consistent with the relatively low summer loads and with the surplus of generation pool-wide.

Okay. Slide 37.

(Slide.)

MR. ETHIER: Okay. Conclusions. I think we've hit on most of these. I do think the cold snap experience, as difficult as that was, I hope we've learned from that or we've instituted some real market improvements that will help reliability in extreme situations, but also just help the markets function well generally. It doesn't do anybody any good if we force generators to bear more risk of gas price uncertainty than they need to. So if we can improve those markets under extreme conditions, it's likely to have benefits in non-extreme conditions as well.

The forward reserve market did provide added incentives for what we need, but we still have out of market payment increases that are problematic and we need long-term resource adequacy to really sort of fill out our market design.

That's all I have.

CHAIRMAN WOOD: The lure for the demand response, to get that curve back on an upward take, price signal?

MR. ETHIER: I think if we get -- you know, part of the problem is when you have a -- and I don't know if this is a problem necessarily, but the flat line we've seen is a reflection of the fact that we're surplus generation. So to the extent that demand responders get the same incentives that generators get through the ICAP market and prices, fewer people are interested in even enrolling in the program because there's not enough money for them if -- let's assume our existing ICAP market sticks around and the price goes to six bucks, you have a much stronger incentive for demand response resources.

So I think there -- when the market conditions change, there is some natural improvement that's likely, but I really do think we need to sort of push beyond the existing regulatory barriers that, you know, I think are at the state level and we really need to work with the states to improve that because I know they want more demand response, too, and we need to figure out how to get that done.

CHAIRMAN WOOD: Thank you.

MR. HEDERMAN: Could I ask a follow-up on that? Is the demand response that is in place at all related to where the load pocket problems are, or do you have a sense of that?

MR. ETHIER: It is, although I'll have to confess part of it is due to the Southwest Connecticut RFP that we issued a year and a half ago. So a big chunk of our demand response is in the Connecticut area -- and maybe that's actually a good answer to the previous question, which is we paid them relatively high dollar amounts relative to what they can get in the market today and we get a lot of demand response. But, you know, you're talking something on, you know, in the $8-9 a kilowatt-month range versus what ICAP is currently paying, which is about 10 cents. So with strong incentives we were able to get it and we were able to get it in the right areas, but until we get that.

MR. HEDERMAN: Yeah. Okay. Thanks.

CHAIRMAN WOOD: Questions for Bob?

(No response.)

CHAIRMAN WOOD: All three of you, thank you very much. We've really enjoyed these visits.

SECRETARY SALAS: Next for discussion is A-3. This is 2005 Summer Energy Market Assessment. It's a presentation by Steve Harvey, Tom Pinkston, Harry Singh, and Colin Mount.

MR. PINKSTON: Good afternoon, Mr. Chairman, and Commissioners. We are pleased to present the Summer Energy Market Assessment for 2005. The presentation will also be made available on the FERC website.

Nationally, most regions have adequate or better reserves and are likely to face no problems this summer. However, higher fuel costs than the past few years are likely to result in higher electricity prices in general. Also, certain locations could face market stress under extreme weather conditions, particularly load pockets in the Northeast, like Southwest Connecticut, and areas in the West, like Southern California. I will present the first part of the assessment and then Steve Harvey will discuss Western market issues and summarize the report.

(Slide.)

MR. PINKSTON: Regional issues vary depending on demand resources and operations. This annotated map of the United States highlights specific regional issues we've identified as important for the summer. I will focus on New

England for a minute and Steve will discuss the West after I'm finished, so for now we'll look at the Midwest where we think the primary issues are the operation and execution of MISOs transition to fully-functioning RTO markets, the coordination between PJM and MISO, and PJM's integration of new areas, most recently of Dominion last weekend.

In New York, we continue to focus on the load pockets of New York City and Long Island. We are also monitoring occasional short-term price spikes in the New York ISO. These spikes appear to be related to recent software changes and are often reversed and corrected. Nevertheless, we are watching their behavior.

(Slide.)

MR. PINKSTON: Let's start broadly with fuel prices. These charts of natural gas and cold spot prices starting in 2003, combined with futures prices for this summer, show that higher prices than last year will continue to put upward pressure on power prices nationally. These effects will tend to be most significant in regions highly dependent on gas-fired generation.

(Slide.)

MR. PINKSTON: We have healthy gas storage inventories, but oil has been driving prices higher. While inventories are comfortably above the five-year average, we've found that gas prices have followed oil prices. For example, as you can see on this chart, gas prices delivered to New York City have traded between number two heating oil and number six fuel oil for several years, with occasional forays higher due to locational scarcity. Most recently, gas prices have remained at a lower end of that price range, indicating reduced gas supply stress. Recent weakness in oil prices -- if dropping below $50 per barrel can be considered weak -- have been closely followed by drops in gas prices, although stronger fuel prices are likely to keep average electricity prices higher than those experienced altogether in the past few years.

(Slide.)

MR. PINKSTON: Now I'd like to speak to New England in a little more detail. Recent New England ISO forecasts have indicated the potential under extreme conditions for some problems in New England this summer. ISO New England's expected 2005 peak load will reach 26,355 megawatts at least one day during the summer and could go as high as 27,985 megawatts during an extended heat spell. The previous record peak load of 25,348 megawatts was sent on August the 14th, 2002. Nevertheless, we think New England should have a slim surplus of capacity provided the summer is not exceptionally hot and loads remain within the expected range.

Specific load pockets in New England could be tighter. Currently Connecticut's capacity is inadequate to serve demand -- or Southwest Connecticut's capacity is inadequate to serve demand and meet reliability requirements. In the southwest, the ISO uses emergency resources and operating procedures to keep the lights on. This year, as in previous years, the ISO has secured 218 megawatts of emergency resource portable generators to help maintain reliability in Connecticut.

MR. HARVEY: Thanks, Tom.

Our review of supply and demand conditions in the West this summer indicates that there may be periods of market tightness, most likely expressed as price spikes and possible interruptions. I want to be clear about this: spikes and interruptions are not the most likely result. We believe that the most likely situation is no serious disruption. However, the possibility remains and we need to take it seriously as we plan our oversight activities for the summer. Let me describe the conditions that might result in disruptions in a little bit more detail.

(Slide.)

MR. HARVEY: We graphed the generation mix for the Western Electricity Coordinating Council to get a general idea of capacity mix for electricity in the West. As you can see, a large portion of the capacity is hydroelectric, close to 30 percent. Much of that is in the

Pacific Northwest. Gas is important, too, with a little more than 20 percent from combined cycle, turbine, and other gas-fired generation, and another 17 percent dual fuel of gas and oil.

Like the rest of the U.S., much of the gas-fired generation is fairly new; most of it developed since 2000. Given Tom's comments before about the price of oil and natural gas, gas-fired generation is likely to be higher priced than in the past few years. This consideration is even more important given the story in the next slide.

(Slide.)

MR. HARVEY: The outlook for hydroelectric generation is not good for this summer. With the exception of California, that faced extraordinary levels of precipitation over the last winter, the West broadly has much less water available for hydro generation than in an average year. Late precipitation improved the situation somewhat, and British Columbia and Idaho now are in better shape than a year ago. Still, Washington, Montana, and Oregon now face very low levels of snow water equivalent. In fact, the latest forecast for the Columbia basin from April through September is 66 percent of throughput of normal.

With hydro at low levels, natural gas is clearly the most significant --

COMMISSIONER KELLY: And Steve, what was the -- what was last season's percent --

MR. HARVEY: I don't know.

COMMISSIONER KELLY: About 70?

MR. HARVEY: I think that's right. This is apparently the driest six years in a row, so it's been sort of cumulative effects over that time.

With hydro at low levels, natural gas is clearly the most significant potential contributor to capacity and energy needs in the West this summer. Consequently, we expect electricity prices in the West to be higher on average than over the last few summers, driven solely by the use of gas-fired generation to make up for the hydroelectric generation. In effect, gas-fired generation will be competing with natural gas storage fill through the summer in the West, possibly affecting prices as well. We'll be watching storage fill to see if there are any potential longer-term effects on gas supply. The western pipeline system, however, appears adequate to handle the total load at this point.

(Slide.)

MR. HARVEY: Now let's consider effects of demand. Extensive economic growth in Southern California has created conditions where, under extreme temperatures, capacity may not be adequate to cover all load. The

California ISO and the California Energy Commission have been actively documenting these conditions and the graph shows the most recent results for Southern California as calculated by the ISO.

Under projected hot temperature conditions, it appears that reserve margins would be inadequate for Southern California in August and very tight in September. Again, I should stress that this problem only appears under fairly extreme conditions and may not appear at all. Nevertheless, we are aware that the California ISO, the California Energy Commission, and the California Public Utility Commission have been working closely with the Governor's office to understand the situation and to look for potential solutions. And Anjalie spoke a little bit about some of those efforts earlier.

The graph does not take into account certain possible demand actions, for example, the effects of interrupting interruptible load. I should note that the graph does assume very high levels of imports into California, including imports from the Pacific Northwest. We have been told that on a peaking basis, capacity of Northwestern hydroelectric generation should be available in California.

(Slide.)

Summer demand conditions are further complicated by recent weather forecasting. The most recent summer temperature forecast from the National Oceanic and Atmospheric Administration is for above normal heat in the West. This NOAA-published map is for July, August, and September and shows widespread forecasted above average temperatures across the West, with much above average temperatures in the Desert Southwest.

If the weather plays out as projected by NOAA, there will be a lot of stress on the western grid. That kind of stress can result in problems beyond simply high demand. Heavily-used equipment is more vulnerable to outages. Outages of generation or of transmission lines could result in localized problems in a stressed western grid. These kinds of outages are not really predictable, but dry weather in the Northwest, for example, could increase the likelihood of wildfires that could, in turn, threaten transmission.

(Slide.)

What would periods of stress look like in western markets for the summer of 2005? First of all, prices are likely to start higher than in the past few summers due to the greater reliance on natural gas instead of hydroelectric generation. With periods -- probably short periods of extreme heat, there could be price spikes to fairly high levels for interruptions of service in extreme cases.

I would note that this possibility is entirely related to market fundamentals. In our view, the likelihood of spot price manipulation is lower in cases of stress than in the past for three reasons: the first is the extent of forward contracting. Many utilities in the West have contracted to cover most of their needs under longer-term contracts. They will tend to go to spot markets only under more extreme circumstances. Second, the Commission has added rules -- most significantly the behavior rules designed to clarify the most significant areas of concern regarding buyer and seller behavior. And finally, we'll continue to oversee market activity through the summer.

(Slide.)

MR. HARVEY: I'd like to summarize our report today, as we always have, by pointing out the areas of oversight we plan to focus on this summer. They include the Western market behavior and activity I've just described, as well as activity in the Northeastern load pockets Tom identified earlier, progress in the on-going MISO market implementation, the price spikes we've noticed in New York since the implementation of their new software and related in certain cases, as Tom pointed out, to the implementation of the new software and in other cases to some of the changes that David Patton spoke about earlier today with regard to how dispatch works, creating some short-term peaks at certain times, and the status of storage fill particularly in the West as the summer goes on.

Please note once again nationally most regions have adequate or better reserves and are likely to face few market problems. Even in tighter areas such as the West and the Northeast load pockets, like Southwest Connecticut, severe problems are unlikely unless hot weather is quite severe.

Finally, I'd like to quickly thank the many contributors listed in the presentation, though in the interest of time I won't read all their names. I would like to say that the development particularly of our views on the West this summer have been formed by close coordination across Commission Staff, including active representation by OMTR, by OEP, by the General Counsel's office, along with the OMOI staff.

Tom, Harry, Colin, and I would be happy to take any of your questions at this point.

COMMISSIONER BROWNELL: I'm looking at -- I don't have page numbers. I'm looking at the snow water equivalent and looking at Washington, Montana, and Oregon at 32 percent for Washington, 59 percent, 53 percent. Hard to imagine that problems are unlikely, but why don't you say a little bit more about that. You talk about reliance on gas. No question that prices are going to be higher in those regions. And do we really believe they have sufficient capacity and what about take-away capacity in California, is that sufficient -- because that was an issue before.

MR. HARVEY: Sure.

COMMISSIONER BROWNELL: So let's say more about that. Because as I recall, maybe incorrectly, last summer we had some heat in California but fortunately it was raining and cold in the Northwest, but even with the good rainstorm in the Northwest, I think that's going to be a problem for California, as well as for the Northwest.

MR. HARVEY: Right. This is one of the questions we've been sort of working with, which is the California estimates are very dependent on high levels of imports -- that would be both from the Northwest and from the Southwest at this point. The question then is at these levels of generation with hydroelectric, can that be covered? And when that question was -- when we raised that question basically with the folks from the Northwest, the answer was very carefully phrased that said we have a lot of capacity, in effect, that hydroelectric plants in effect represent capacity and that during peak periods we can deliver energy but that we need to get paid back in energy in order to maintain the water behind the dams.

There seemed to be comfort that that would be possible and, having raised that question with Californians and with those in the Pacific Northwest, that seems to be the deal implicitly in there is that during peak periods in the South they'll deliver energy and they'll get energy back at other times. If that works -- and I've been told no reason why it wouldn't work -- then in theory that would be okay.

COMMISSIONER BROWNELL: It's a great deal if you have it, but it doesn't look like they have it. I mean, in theory it's terrific.

MR. HARVEY: Right. Right. And again it has to do with water behind the dam and then selectively running it. Now there are other questions because there are other constraints on how you run a dam -- recreational reasons, fisheries, and those sorts of things -- but again, having asked that question explicitly, what we've been told is given that deal it will be possible to manage.

COMMISSIONER BROWNELL: BPA said that?

MR. HARVEY: It was the Northwest.

COMMISSIONER KELLY: Steve, who does that coordination? Who's responsible for the arrangements and implementing the arrangements?

MR. HARVEY: As far as I can tell, no one is responsible for implementing the arrangements. The use of that capacity, sort of on a spot basis, coming out of the Northwest into California, would presumably be through the ISO and through arrangements with BPA, for example, in that case.

And so my presumption is that it would be a deal between those entities that would work that out explicitly.

COMMISSIONER KELLY: Would the WECC be involved? I mean, there is no regional --

MR. HARVEY: Right.

COMMISSIONER KELLY: -- planning center in the West.

MR. HARVEY: Right.

COMMISSIONER KELLY: So I'm wondering how likely it is that this kind of arrangement, which sounds terrific, can be implemented and who is going to be responsible for implementing it.

MR. HARVEY: Again, as best I can tell, the responsibility will be the California ISO's and entities in the Northwest, probably, and, presumably, BPA is the most significant one.

WECC is aware, I believe, of the issues and aware of the sort of back-and-forth, but I would say there is no direct coordination of that ahead of time.

COMMISSIONER KELLY: Mr. Chairman, can I ask Anjalie a question?

CHAIRMAN WOOD: Yes. Oh, good, she's still here.

COMMISSIONER KELLY: Thanks. Thanks, Anjalie.

Anjalie, has the California ISO been involved in this kind of an arrangement or coordination before?

MS. SHEFFRIN: Historically, the West has used this type of arrangement. At the height of the energy crisis, there were arrangements where utilities in California would buy power on-peak and return twice that amount off-peak, so those are common arrangements.

In terms of who would --

COMMISSIONER KELLY: But was that an arrangement that happened after the market -- while the market existed, or afterwards?

MS. SHEFFRIN: Afterwards, right at the height of the crisis when the market melted down.

COMMISSIONER KELLY: And did it involve individual decisions by the load-serving entities in California, or was it coordinated through the ISO or the

Governor's Office, or the PUC?

MS. SHEFFRIN: A large amount of those exchanges are bilateral exchanges, so they're worked out between the utilities and BPA, and they are bilateral contracts that are signed, so the majority of them are in those types of contracts.

COMMISSIONER KELLY: Thanks.

MR. LARCAMP: All I will say is, last time, a couple of utilities weren't meeting their load, and that there were tremendous amounts that the ISO had to acquire in real time.

MR. SINGH: Yes, we had conversations with some utilities that have indicated to us that they have been in discussions with entities in British Columbia, like PowerX and with BPA to discuss such arrangements.

COMMISSIONER KELLY: Well, in your new executive director's connections with British Columbia, that should be helpful. Thanks.

CHAIRMAN WOOD: If they'd want to play. There's a lot of feuding going on in that market, that I don't think is very constructive for the summer.

Are there people that aren't going to play because of uncertainty about the rules? I mean, is there uncertainty? I mean, you hear some things, just from the trader talk, but what do we really think with regard to, you know, the likelihood of people just not participating in the market?

MR. HARVEY: We've spent some time talking to various participants in the Western market to try to get a sense of that. Now, obviously, talking, as FERC Staff talking to the participants in the market will -- we're likely to get a certain kind of story in certain cases, but we have really been doing a fair amount of outreach on that.

And it's a fairly uniform response, that there is a great deal of concern, particularly if prices go high, that transacting in this market could be dangerous. I think that comes from a couple of perceptions:

A lot of it is, of course, how history has played out for 2000 and 2001; part of that is also how the ceilings would kick in in terms of price ceilings and how those would be applied.

And what we're hearing is that, in effect, there are risks associated with payment; there are risks associated with being investigated; there are risks associated with reputation by participating in the markets, if they really heat up.

And so we've heard, in a fairly widespread way, that there's not a lot of interest in participating, if things get fairly extreme. Now, many of these entities have done long-term contracts with the utilities in California, and that may mitigate some of that effect by going to the longer-term contracts, early on in the process.

But that concern has been expressed. Obviously, that would be very bad under extreme circumstances, to have people, you know, hesitant to go into that market.

CHAIRMAN WOOD: Well, you know, in light of the way we kind of move forward, you know, through pretty brambly patches with the indexes, it would be nice if people could get comfortable that, you know, within the parameters of what the Commission has laid out over the last four years, there is an umbrella under which to operate, even in the high-price environment, that there won't be some after-the-fact investigation, that any changes we'd make to the market rules, as we just did last month with California's market rule, would be prospective in nature.

If there's an opportunity here between now and the summer peak for the Commission to provide some clarity, I would just like to publicly invite anybody in the marketplace to contact you guys in RMTR and OMOI and OEP, to talk about any concerns they have, and y'all can bring them back up to the Commission, and, if necessary, we'll talk about them in public, but at least we can be aware of what those concerns are.

It is important, I think, in light of our recent past history, to make sure that we aren't faced with the gotcha, yet we also have people know what the rules are and they play by them. There's an opportunity to satisfy demands in this scarce market, when you see -- what is the -- is it Washington State with the most supply?

COMMISSIONER BROWNELL: Yes, 32 percent.

CHAIRMAN WOOD: By far the biggest hydro capacity state up there. Gee, I mean, that's very troubling. So, I think this could be a western-wide issue. Southern California would be, as we all talked with Anjalie and among ourselves, be the exacerbating point, but it doesn't look like, from the weather map, it's going to be just there.

MR. HARVEY: It could be much more widespreading, depending again on the conditions of the grid and the operations there.

CHAIRMAN WOOD: Well, my Rosary has lost a few beads over the last one of these summers, I guess I'll have to get a new one with the new Pope's face on it, or something.

COMMISSIONER BROWNELL: You know what, though? I think, in addition to that, Pat, maybe we could ask the team overseeing the Western markets to really work with the Northwest Coordinating Council, if they have the most accurate information. Let's dig down into this Northwest situation.

I think that, given the experience in 2001 when prices go up, there will be an automatic assumption that it's market manipulation, when it's pretty clear that at 32, 39 and 53 percent, they're going to be relying on gas.

We ought to look at the potential gas prices, kind of what that might look like, so that people are actually prepared and understand the fundamentals.

I think that's critically important, and I think we ought to validate the data and maybe work with WECC as well.

CHAIRMAN WOOD: Anything else from the team?

MR. HEDERMAN: Can I just clarify one point about that 32 percent? I'm sure Mark Robinson could speak more knowledgeably to this than I can, but notice that the Idaho and Montana numbers are not quite as severe, and they have significant downstream capacity.

So, in other words, the snow pack is going to move down out of the mountains and that will flow through Washington, so that the 32 percent is just talking about the snow pack in the State of Washington. So, the 60 percent is probably more the number that tells you what you're going to get out of it, relative to an average year.

COMMISSIONER BROWNELL: Sixty percent isn't 100 percent, and I think you'd have to look at the growth numbers in the Northwest, whose economy has also improved, perhaps not as much as California.

I just think that we better have a very accurate picture. We've picked on California, and we'll continue to do that, but I think we better make sure that everyone understands exactly what the potential impact is.

It also might not be a bad idea to get NOAA over for a briefing. You know, we've talked about temperature, but storms are a major issue in California. Actually, the Northeast -- I was talking to someone the other day -- hasn't had a hurricane in 20 years, and that's about their average.

That has, I think, huge implications that need to be considered, as well.

CHAIRMAN WOOD: I'm looking at the slides with all the different breakout of the regions, and I'm looking at NWP, which I assume would be what we're talking about, and, you know, if you're talking about hydro at, you know, half of the rated capacity -- it's just hard to know how to read the hydro numbers, just because of the energy nature of that resource.

MR. HARVEY: Right, right.

CHAIRMAN WOOD: You know, I do think, even with what looks like an attractive reserve margin, it's, from your numbers, not really going to be there. It could be there peak, but it won't be there sustained. You had a lot of needle peaks, which is not necessarily the pattern.

MR. HARVEY: Clearly, the way that the implicit deal works, is to use that hydro for peaking, in effect, and what that exactly means, given the large addition of gas-fired generation in the last five years, to the overall gas system, is not clear to us right now.

So an average or warmer summer out there, you know, we're going to learn, doing as much research as we can and as much coordination as we can, will be important.

COMMISSIONER BROWNELL: This would be the summer that I'd like to not learn as we go.

(Laughter.)

MR. HARVEY: That's understandable.

CHAIRMAN WOOD: In that CNB chart, while I'm on that one, Steve, what is the "Other". It has the margin in California and "All Other." Is that renewable or what?

MR. HARVEY: I am not completely sure, so I would hate to give you the wrong answer.

CHAIRMAN WOOD: That's the only one that I don't see on the list.

MR. HARVEY: Yeah.

CHAIRMAN WOOD: All right, any -- Joe, Nora, Sudeen?

(No response.)

CHAIRMAN WOOD: All right, I thank the team.

SECRETARY SALAS: Next in the discussion agenda is a joint presentation of E-6, Standards for Business Practices and Communication Protocols for Public Utilities, and G-3, Standards for Business Practices of Interstate Natural Gas Pipelines. This is a presentation by Marvin Rosenberg, Jamie Chablinsky, Kay Morice, Mike Goldenberg, and Gary Cohen.

MR. ROSENBERG: Good afternoon. There are two items on this agenda that are related to standards developed by the North American Energy Standards Board. One item is Notice of Proposed Rulemaking and the other is a final rule.

E-6 is a Draft Notice of Proposed Rulemaking, proposing to adopt the first set of standards developed by NAESB's Wholesale Electric Quadrant. It follows procedures used by the Commission for NAESB's natural gas standards, and proposes to incorporate the standards, by reference, into the Commission's regulations.

This first set of standards contains OASIS standards and standards which complement NERC's Version 0 reliability standards. Once adopted by the Commission, all public utilities will be required to abide by these standards.

Until now, the Commission had relied on ad hoc working groups to develop and maintain OASIS standards. With this NOPR, NAESB, which has a successful record of developing natural gas standards for almost a decade, is taking over this function and has begun the process of revising OASIS standards to meet industry business needs.

G-3 is a Draft Final Rule incorporating, by reference, the most recent business practices developed by NAESB's Wholesale Gas Quadrant.

The standards include Version 1.7 of NAESB Business Practice Standards and standardized posting requirements for both gas quality reporting and Order No. 2004 affiliate standards.

Any questions?

CHAIRMAN WOOD: How would you characterize the level of detail that both sets of standards go into?

MR. ROSENBERG: They go into quite a bit of detail.

CHAIRMAN WOOD: I would just say that since I was here the last time, I've been a big fan of this group and their predecessor group GISB, because, god knows, we're not good at the detail, and the people that have to live and die by this in the commercial marketplace, are those people, and they've found a process by which they can corral all of those different interests together and come up with an ANSI-certified process to get these done.

I'm glad to see us moving this way on the electric side for the first time, which why I wanted to call attention to it today, because we're following in a track that has worked very well in the gas industry, which is now in Version 1 - point?

MR. ROSENBERG: Seven.

CHAIRMAN WOOD: Seven, so we've done this quite a few years now.

We've done it quite a few times on the electricity side, so I'd say it's been really fun to watch this organization evolve, a voluntary organization evolve over the last 15 years of my career and I'm pleased that we have a package here today that could potentially, if the Commission adopts it on final rule, move forward with some type of standardized approach in the electric industry.

COMMISSIONER KELLIHER: The Commission issued an Advance Notice of Proposed Rulemaking on OASIS II in July of 2000. Does this obviate the need to move forward on that or these are different issues?

MR. ROSENBERG: These are different issues.

COMMISSIONER KELLIHER: Okay. Thank you very much.

CHAIRMAN WOOD: Nora, you're first.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

Thank you all.

SECRETARY SALAS: Next for discussion is E-7, International Transmission Company. It's a presentation by Elizabeth Rylander and Phil Nicholson.

MS. RYLANDER: Good afternoon, Chairman Wood and Commissioners. The transaction addressed in this filing involves a public offering of, eventually, all of the common stock of ITC Holdings Corporation, or ITC.

ITC wholly owns International Transmission Company, an independent transmission company within the Midwest ISO. Applicants state that access to the stock market to raise additional investment capital will allow ITC to repay some of its outstanding debt and will enhance ITC's ability to provide International Transmission Company with funds to invest in and improve transmission infrastructure. The transaction represents an indirect disposition of jurisdictional assets that requires Commission authorization under Section 203 of the Federal Power Act.

Applicants also request that the Commission confirm that, under this new ownership structure, International Transmission Company will remain independent of market participants as defined in Order Number 2000. The draft order would confirm that International Transmission Company will continue to be independent of market participants and grant Section 203 authorization for the transaction. The draft order would approve applicant's proposal to limit the acquisition of ITC shares by any market participant to less than 5 percent in order to address concerns that any market participant could exercise control of International Transmission Company and compromise its independent. The draft order also would approve applicant's proposal to allow ITC to redeem shares to the extent necessary to bring a market participant's holdings below 5 percent. Finally, in connection with these conditions, the draft order would impose certain reporting requirements on ITC.

Thank you.

CHAIRMAN WOOD: Thank you, Elizabeth.

COMMISSIONER BROWNELL: Thank you for the quick turnaround on this. I think this represents an enormous step forward in the vision the Commission has expressed to have business models whose sole focus is the transmission business and it, I think in a very real way, given the performance that we've seen so far, directly aligns the economic interest of the company with the economic and reliability interest of the customers.

A business model that is incented to leverage this asset in an appropriate way, which is to bring value to the system, reliability to the system, I think really gets you to a market-driven system. And given the statistics we've seen from this company and other independent transmission companies, the level of investment increases, the level of new of efficiency increases, the options for customers increase, the quality of service improves, so I think this really is what the Commission and others have envisioned in introducing competitive models.

And we look forward to a time and we've been working, I think, to make sure that we have the right policies in place to encourage the kinds of business models that we see bring value to the marketplace. So we've all been working pretty hard, but this is I think a really important day. So congratulations to the team and keep up the good work, we're going to be watching closely those investment levels and quality of service. And thank you very much for bringing this forward quickly so that this can get expedited.

COMMISSIONER KELLY: The anticipated public offerings are a significant development in and a validation of the Independent Transmission Company business model. I think there's no doubt about that. I'm pleased to be a member of the Commission that is working to support that. I believe, as Nora has stated, that independent transmission companies can bring and have brought many benefits to transmission customers in their regions.

They are a different business model; obviously not the only business model and certainly not the traditional business model for getting transmission built. They have some advantages over existing ones and some disadvantages. The advantages include the fact that they have no internal competition for capital as between generation and transmission so they have every incentive to invest in transmission and that's something that all sides agree is sorely needed today.

They also can easily achieve revenue certainty with one stop shopping at FERC, because they don't serve bundled retail load, they don't have to -- the added uncertainty of revenue recovery through the state regulatory process.

So I support this order. I believe that we have taken care of concerns that the ITC's will remain independent primarily by having a 5 percent ownership threshold for market participants, no voting rights beyond 5 percent, and the right to redeem stock above 5 percent. And I think this should permit ITC to raise more capital to invest in the transmission grid and that's clearly to the public good.

COMMISSIONER KELLIHER: As Staff indicated, the order grants Section 203 authorization for the transaction and confirms that ITC will continue to be independent of market participants, and the proposal is consistent with the merger policy statement and I support the order.

I do think the Commission has to revisit its policy with respect to independence of transcos. We've already seen that the current transcos, ITC, ATC and others, are a proven vehicle for securing investment in transmission. The conference the Commission held last month pointed to the very high levels of investment by both ITC and ATC. ITC, of course, is an independent transco; ATC is an affiliated transco. Nonetheless, they're both securing substantial investments.

Now even though the current transcos have been investing a lot in transmission, they do still have a small footprint, and expansion of the current transcos has proved difficult. I think if the Commission wants to see large transcos established, it probably will have to revisit its policy on independence, otherwise transcos can only expand through cash acquisitions system by system and, of course, by investing in their current footprint.

So I do support the order but I do think it suggests a need for a possible policy change. Thank you.

CHAIRMAN WOOD: Ate that one up.

The thin ladies have sung and the thin man has sung, so I'm ready to join the orchestra and vote for it.

SECRETARY SALAS: Aye and hallelujah.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: And finally on the discussion agenda we have a joint presentation of G-2, Inquiry Regarding Income Tax Allowances, and E-56, Transelect Entity

Path 15 LLC. It's a presentation by John Robinson and Heidi Gruner, also Andy Lyon and Edward Ristway.

MR. ROBINSON: Mr. Chairman and Commissioners, I'm John Robinson and I'm presenting Draft Order G-2, Policy Statement on Income Tax Allowances. Draft Order G-2 addresses the July 24th, 2004 remand by the Court of Appeals for the D.C. Circuit in BP West Coast Products v. FERC. The Court concluded that the Commission's prior Lakehead orders did not adequately justify why a partnership should receive an income tax allowance in proportion to the partnership interest held by a corporation but no income tax allowance in proportion to those interests held by individuals.

The Court's opinion was based on the Commission's assumption in Lakehead that partnerships do not pay income taxes. Based on the record in this proceeding, the draft order concludes that a tax allowance should be allowed for all entities, including partnerships and limited liability corporations generating public utility income, provided there is an actual or potential income tax liability on that public utility income. Thus, if a partnership meets the standard, the operating entity would be permitted an income tax allowance in proportion to the partnership interests that have an actual potential income tax liability.

The draft order also concludes that income taxes are a cost of the partnerships operations that are paid by the partners. Because partners normally have an actual or potential income tax allowance based on the partnership utility income, the draft order concludes the assumption in Lakehead that partnerships have only phantom income taxes was incorrect. Thus, partners and pass-through entities would be granted an income tax allowance if the holders of such interest have an actual potential income tax liability. Whether such an income tax liability exists would be decided in individual rate proceedings.

Heidi Gruner to my right will now present the related item, E-56.

MS. GRUNER: Good afternoon. In an order issued on December 2nd, 2004, the Commission allowed Transelect Entity Path 15 to include in its transmission revenue requirement an income tax allowance associated with its return on common equity for the first three years of operation. However, the Commission made the income tax allowance subject to refund and subject to the outcome of the generic proceeding established in Docket Number PL05-5.

This is just describing G-2. E-6 is a draft Order that denies the request for rehearing of the Commission's acceptance of the income tax allowance. The draft Order also directs TransElec, NDT Path 15 to make a compliance filing demonstrating that it meets the standards set forth in Docket No. PL-5-5. Thank you.

CHAIRMAN WOOD: I want to thank you both. I think this is certainly a big issue for the Commission, that, as we have found out from, wisely, I think, doing the policy statement, has implications across all of regulated industries, not just the oil that it started from, but gas and electric as well.

And it curious; I started my career as a Commissioner ten years ago with the phantom tax issue. It was so, so hot in Texas that it was on the front page of all the papers, and explained as phantom taxes, in a pretty, quite frankly, difficult-to-defend way, but the Supreme Court kind of pulled us out of the mess down there.

But this additional wrinkle on this issue, has made it even more difficult to kind of pierce through the rhetoric and get to the real substance here. I want to just thank you for allowing that to happen in this document.

I think it really does kind of, in a balanced and fair way, restate what I think the Commission has been trying to do for the last couple of decades here with this particular issue, and, I think, actually got it right this time, and instead of trying to parse it, as we did in Lakehead, going back to a method that says we're really going to look at what the actual tax obligations would be or are, or both, for the different owners of these types of operations, partnerships.

I think it was necessary to clarify that, and I look forward to, I think, in the subsequent meetings or so, we're going to need to deal with the remand from which this arose. I expect we'll do the same application on a specific basis there, as we've been today in Heidi's case with the TransElec.

Now, the way the TransElec was left, Heidi, was that they will then come back and do what?

MS. GRUNER: A compliance filing to demonstrate that they meet the standards in G-2.

CHAIRMAN WOOD: Okay, great. Thank you all for the expedition and also for the time you took to listen to, I think, a lot of folks. We heard them, too. It was probably ten percent of what you heard, but folks on all sides of these issues, feel very strongly about it.

COMMISSIONER KELLY: Well, I am very pleased with the policy that we announced today, and I believe it is appropriate to permit an allowance for all partnership interests, or similar legal interests. Our decision has a significant qualification, and that is that any pass-through entity seeking an income tax allowance in a specific rate proceeding, must establish that its partners or members, have an actual or potential income tax obligation.

Obviously, this is a case-by-case, factually-laden decision, and both EEI and Wisconsin Public Power have suggested that that issue be addressed in a case-by-case way, in individual rate proceedings, and we endorse their suggested approach.

Our policy statement clarifies one point that I'd like to amplify on today, and that is that this decision should not result in increased costs to public utility ratepayers, and, in fact, it may actually reduce costs, because the partnership or LLC has a lower weighted marginal tax rate, as well as fewer administrative expenses than the normal corporate ownership form.

I also believe that our policy statement today addresses the D.C. Circuit's concern, as expressed in the BP West Coast Products case. The record that was presented to us in the course of this proceeding, suggests that there is a substantial amount of existing investment at issue today and in this proceeding.

For example, although we don't have specific dollar amounts, Duke Energy Corporation testified that 75 percent of the $14.4 billion in energy infrastructure invested for the years 2001 through 2003, is held in pass-through entities.

The Coalition of Publicly-Traded Partnerships has told us that there are currently 20 publicly-traded partnerships trading on major exchanges, which own and operate oil and gas pipelines, and that market capitalization of publicly-traded partnerships was $47.3 billion in 2004, and the publicly-traded partnerships owning and operating energy pipelines, have market capital of $38.5 billion.

Thus, we heard that the concern that disallowance of income tax costs in rates for partnerships, would chill much needed investment in additional infrastructure, and I trust that our decision today will create a thaw and give parties the confidence that they need to continue to invest in these projects, which this country needs.

CHAIRMAN WOOD: As long as you --

MR. BRUNER: As the Staff indicated, the BP West Coast decision raised a lot of regulatory uncertainty regarding the Commission's policy in this area, and as the Chairman noted, partnerships and pass-through entities are used to finance the whole spectrum of the facilities under our purview.

So, there was a need for the Commission to clarify its policy, and I think the approach that we took was correct. We issued a Notice of Inquiry, got very significant public comments from cross sections of the various industries, and carefully reviewed the comments.

And this policy statement, which I think will be unanimous -- we'll find out in a moment -- does represent the Commission's hopefully unanimous view. And I believe the policy is legally sound, and have no doubt we will find out.

(Laughter.)

COMMISSIONER KELLIHER: But I support the Orders.

COMMISSIONER BROWNELL: Aye. I'm sure we'll find out in the affirmative, Joe.

COMMISSIONER KELLIHER: Aye.

COMMISSIONER KELLY: Aye.

CHAIRMAN WOOD: Aye.

All right, meeting is adjourned. Thank you all.

(Whereupon, at 1:45 p.m., the open session was concluded.)