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 :

STRICKEN ITEMS :

- -x

COMMISSION MEETING - 786TH REGULAR MEETING

Hearing Room 2 C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, February 27, 2002

10:10 a.m.

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APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

SECRETARY MAGALIE ROMAN SALAS

ALSO PRESENT:

DAVID HOFFMAN, Court Reporter

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FEDERAL REGULATORY ENERGY COMMISSION

786TH REGULAR MEETING

(10:10 a.m.)

CHAIRMAN WOOD: Good morning. This meeting of the Federal Energy Regulatory Commission will come to order to consider matters which have been posted for February 27, 2002. Please join me in the pledge to the flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: It was nice to see that flag in a number of metal ceremonies over the past two weeks. It's just as nice to see it back there.

Before we start, Ms. Linda has something to say.

COMMISSIONER BREATHITT: I have an announcement this morning. I would like to announce that Mary Bench who has been with the Breathitt office for a little over four years is sadly leaving us but happily joining Sullivan & Wooster, a Boston law firm, with a new Washington office. Mary is going to be sorely missed by me and the rest of the people in my office. She kept us laughing, needless to say, through lots of long, tedious difficult days that we've had in the past year-and-a-half, and is a terrific writer, is a fine person, and is very loyal, and I would like to congratulate Mary on her new business opportunity and to tell you that we will all miss you very much and to thank you in short, simple words how grateful I am for your wonderful years of service in the Breathitt office.

(Applause.)

COMMISSIONER BREATHITT: I would also like to announce that Dave Fairburg, who is an attorney in OGC, will be coming up on a detail and will be starting this Friday.

And, Mary, no more cases to read over the weekend.

Dave, would you please stand so everybody can recognize you. Thank you.

(Applause.)

COMMISSIONER BREATHITT: That's all I have, Mr. Chairman.

CHAIRMAN WOOD: Thank you very much.

Madame Secretary?

SECRETARY SALAS: Good morning, Mr. Chairman, good morning Commissioners. Your consent agenda for today is as follows:

Electric E-2 through E-4, E-7, E-9, E-11, E-12, E-15 through E-18, E-20, E-23 through E-26, E-29, E-31, and E-33.

Gas G-2 through G-5, G-8 through G-11, G-13 through G-17, G-19 through G-29, and G-31 through G-33.

Hydroelectric H-1, H-4, H-5, and H-7.

Certificates C-1 through C-6 and C-8.

The specific vote descriptions for these items are as follows: E-3 Commissioner Brownell concurring. E-18 Chairman Wood not participating. E-20, Commissioner Breathitt concurring, Commissioner Brownell concurring. G-8 Commissioner Breathitt dissenting in part. G-11 Commissioner Breathitt dissenting in part. G-13 Commissioner Breathitt dissenting in part and Commissioner Massey votes first this morning.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye with partial dissents and concurrence noted.

COMMISSIONER BROWNELL: Aye with concurrences noted.

CHAIRMAN WOOD: And aye, including not participating on E-18.

SECRETARY SALAS: The first discussion item this morning is E-34, Electric City Market Design and Structure. More specifically today, you will hear a presentation of the RTO cost benefit analysis report. Presenting for you this morning at the table from the Commission Scott Miller and Bill Meroney, and at the table from ICF Consulting John Blaney and Jim Turnure.

CHAIRMAN WOOD: To introduce this, I'd like to just put it in the context of what was going on here. On November 7th, we initiated a cost/benefit study on the RTO policy. While other studies have been performed by the

Commission in the past, to capture national net benefits, we have not further disaggregated that to try to understand the net results on a regional level. Today we received the results of the study from the contractor, ICF, as introduced by the Secretary.

I'd like to say a few things about the generous involvement of some of our state friends. ICF consulting and FERC Staff had the benefit of working with an advisory team of some of the state commissioners from across the country. The members of this team are James Buddy Atkins from South Carolina who I'm pleased has joined us here today at the table, Michael Dworkin, Chair of the Vermont Commission, whom I understand is joining us by phone, Chairman Marilyn Showalter of the Washington Commission who is also I believe joining us by phone. Alan Schreiber of the Ohio Commission, David Schwanda from Michigan, and Connie White from Utah.

I'd like to thank these hardworking folks and of course those on our Staff and the consultant for helping us out on the study. While the presence of the commissioners, the state commissioners, does not imply they agree, it was very valuable to us and I believe to the consultant, from my understanding, that we had access to their views, issues and requests. We very much appreciate the time that the state commissioners took to help us out and we hope this has made for a more credible product.

Our efforts do not end here, as I believe will be detailed a little bit more later between March 4th and March 15th, our Staff and the consultants will hold a series of conferences and teleconferences with state commissioners, members of the industry, customer groups and other parties to discuss the study's results. We'll announce the dates and times for those specifics shortly so anybody interested can participate.

We also have with us the members of staff here and with no further adieu, I'd like to turn it over to Mr. Miller to introduce the project.

I'm sorry, I was also told Commissioner Atkins would like to say something first.

MR. ATKINS: Thank you, Mr. Chairman. Again, I appreciate the opportunity to be here today. Let's see if I can gather up my notes that I have momentarily lost. I do appreciate the opportunity to be here today and I want to thank the Commissioners and all the Staff that I have the opportunity to work with. I think moving forward, it's important that we keep in mind where we've been. These are extremely important issues and ones which will have a major implication on supplies used, generation issues, and how we scope RTOs out into the future. And I think we'll have an important role in how states move towards their evolving markets. Being a southeastern commissioner, we are still regulated there, and clearly there are a number of important decisions that we are going to have to make in our general assemblies as we move forward. I think the key to this is to make sure that we're open minded, and that ultimately we have a forward looking, robust model that looks at a whole range of issues which hopefully will optimize system costs in the electricity system. Those might include siting of transmission and generation and the planning that goes with that, needed transmission improvements, and also, and I think very importantly, the design and implementation of fair and reasonable transmission operating rules and tariffs.

I think to that end, the cost benefit study that's been initiated by FERC that has been supported by NARUC should begin to offer guidance to all of us towards a consensus of how these RTOs should be implemented. As a state commissioner, I think it's important for everyone to realize that I have to keep in mind that we again remain vertically integrated in South Carolina and in most of the southeastern states, and it's important that I keep in mind the potential impacts there are to consumers and incumbent utilities. However, I believe that we must look forward to the future and be open to the potential benefits which could accrue from well-designed RTOs.

As a finder of fact, I have to remain skeptical until the data are in. I must say I'm really looking forward to going over the outcome of the model, and to working closely with the FERC Staff and with the consultants as we move forward to a resolution of this issue.

Let me emphasize again, as I have in many other situations, the importance and critical role which I believe has to be placed on formalizing the process and collaborative effort between the FERC and state commissions. I think we have to do that in order to continue to move forward to resolve this issue in a timely and efficient manner. Mr. Chairman, I just again appreciate the opportunity to be sitting up here at the table and having the opportunity to have input both today and as a member of the Advisory Group.

CHAIRMAN WOOD: Thank you. We'll thank Buddy for being here. They are kind of numbers guys and I appreciate your comments.

Mr. Miller? Mr. Patton, are we patched in? Welcome, Marilyn. It's Pat and the gang. We're going to turn it over now to Scott Miller on our Staff to introduce the project.

Scott?

MR. MILLER: Good morning. It's nice to see a fifth Commissioner at the table.

(Laughter.)

MR. MILLER: The main purpose is to give a briefing, an overview of the results that we got from the cost benefit analysis that we initiated back in November. Before I turn this over to ICF Consulting, to give us an overview of the results, the presentation that you're about to see and the report itself should be up on the Web site shortly.

Let me say a few words about the process involving the state commissioners because we had heard so frequently from a number of the states that they wanted a cost benefit analysis that drove down some regional results. The Commission initiated a process which was a little bit unique but was designed to try to give us the benefit of the perspectives of the state commissioners. Working with NARUC, Chuck Gray and Charlotte Barklin, we arrived at a group to work with us on assumptions and issues that were important to the states and a group that was provided regional diversity, a background of people who either had some modeling experience or had expressed an interest in such a model being run, and a wide variety of perspectives with regard to RTOs.

As you mentioned, Mr. Chairman, there were a number of them but it had to be kept to a relatively small group to keep the process manageable. But we did meet with them by teleconference on at least five or six different occasions and actually had them come to the ICF Headquarters for a nearly all day event to go through the logic of the model we used, and we very much appreciated their input. It was most useful.

I can say that we tried to incorporate nearly all of the issues that were raised by the states. There were some that were difficult from the perspective of the model, but we did try to take all these seriously. Before turning it over to ICF, let me say a few words about their qualifications.

ICF has been around for quite some time, and has a fairly storied history in the 25 years that it's been around for first working on the U.S. Government's response to the oil embargo in the 1970s, working on Project Independence. They also lent their expertise to a number of initiatives which were important to both energy and environmental policies. These policies include the Natural Gas Policy Act, the Clean Air Amendments, and most recently the President's proposed Clear Skies Initiative.

Working for us, they've provided analysis for the environmental impact statement for Order 888, the environmental assessment for Order 2000, and they have done a number of studies to support U.S. Agency for International

1 Development, the World Bank, and the Environmental

Protection Agency.

Without further adieu, I will turn this over to John Blaney who is the Vice President for ICF and we'll go through the first part of the overview.

MR. BLANEY: Good morning. I want to thank the Chairman and the Commissioners and the FERC Staff and the members of the State PUC Panel for working collaboratively with us on this study. And we are pleased to present the results this morning.

On page 3 of our presentation, you see an outline of the scope of the discussion for this morning.

(Slide.)

We're basically going to try and cover three things. We're going to first talk about just providing an overview of the study. Secondly, we're going to talk about the process and the analytic approach that was used, and lastly we're going to talk about the results.

(Slide.)

Turning to page 6 of the presentation, you see a summary of the approach that was used. The Commission announced further cost benefit analyses in federal/state consultations in the November 7th, 2001 Order. The purpose of the analysis that we understood, as the Commission said, was to "determine whether, and if so, how RTOs will yield customers savings, and to provide a quantitative basis for the appropriate number of RTOs." To that end, ICF undertook developing computer modeling scenarios by combining sets of analytic assumptions because the Commission described three major types of economic benefits in Order Number 2000. Three policy scenarios were developed to analyze relative contributions of different assumptions to economic outcomes.

The first study, the analysis that we did was a base case that embodied current regulations resulting from FERC Order 888. In addition to that base case which set the framework for the analysis, we did three additional core policy scenarios. The first was a transmission and generation case which combined transmission efficiencies with improvements in generator performance. The first two types of benefits that the Commission identified.

Secondly, we did a transmission-only case in which we tried to isolate the improvements that would result in the transmission grid only as a result of FERC Order 2000, the adoption of RTOs. Lastly, we did a demand response case which added in a limited demand response benefit to the transmission and generation case assumptions. In addition to that, two sensitivity cases were also developed, one for a larger RTO case and one for a smaller RTO case, to examine the impacts of varying the RTO's scope alone.

(Slide.)

On page 7, you see a summary of the results. The policy scenarios result in a wide range of potential economic benefits, production cost savings for the entire system range from $1 billion to $10 billion per year. On a net present value basis over the 20-year time frame of the study, total product cost savings range from $7 billion to $60 billion.

Estimates of RTO establishment costs range from $1 billion to $5.75 billion, but these are one-time start-up costs. On a net basis, the results of the study show that implementation of RTO policy leads to gains, even if RTO benefits are relatively low while costs are relatively high.

The sensitivity cases examining RTO results show that larger RTOs lead to larger economic gains. These effects are in the range of one to three hundred million dollars per year. The assumption that RTOs lead to improvements in generator efficiency, particularly through better generator performance, is the most important factor determining the results.

Energy price impacts vary across regions. Most regions show price declines, but a few regions show price increases. The increases are small and transient but raise issues of equity and revenue distribution.

That provides a brief summary and overview of our study approach and results. What I would like to talk about now briefly is the process and analytic approach that was used. Turning to page 11.

(Slide.)

MR. BLANEY: Mr. Miller already described the collaborative process that we used. We worked closely with FERC Staff to develop an initial framework of the study. A state PUC panel was also engaged via a series of conference calls to consider issues that should be addressed in the study, analytical methods and specific state concerns. And on January 8, 2002, an all day meeting with the state PUC panel and FERC Staff was held at ICF's headquarters in

Fairfax, Virginia. This collaborative process framed issues and provided input into the scenario selection. Actual analysis and final results were not subject to FERC or state official review or revision.

I'd like to briefly now talk about the modeling framework that was used, and I would like to turn to page 14.

(Slide.)

MR. BLANEY: There you see a diagram depicting the integrated planning model which was the tool used for this analysis. You see depicted there the major inputs and outputs into the modeling system. The starting point on the left-hand side as it's depicted there is the database with information on every boiler and generator in the United States as well as information describing the cost and performance of new generation technologies.

The model inputs also include electric demand, gas supply representation, coal supply representation, as well as a very detailed representation of air emission regulations as well as pollution control strategies for dealing with them. Obviously, another very important input into the model was the specification of the RTO regulatory scenarios that we will be describing shortly.

Having run the model for the base case and for the three policy scenarios and the two sensitivity scenarios, the results that come out of the model include electric generation capacity additions, fuel consumption, both natural gas, coal and oil, electric prices as well as capital O&M and fuel costs as well as NOX, SO2 and carbon emissions.

(Slide.)

MR. BLANEY: Turning to page 16, you see a depiction of the geographical structure of the model. We divide the U.S. electric system into 32 regions. The starting point for those regions are the NERC regions. In addition to that, we further subdivide those NERC regions to capture what we view as significant transmission bottlenecks in the electric system. So we have a representation of all the electric generators in the United States. Those are assigned to these 32 regions based on their location. And then we have estimates of the transmission capacity linking these regions so that we can model the generation and the flows for the entire U.S.

(Slide.)

MR. BLANEY: I would like to briefly, turning to page 18, describe some of the key features of the model. One of those features is a very detailed representation of coal supply. We have 40 different coal supply regions in the model, each coal plant in the model is assigned to one of 41 different coal demand regions, and there's a coal transportation matrix that links that demand and supply up.

(Slide.)

MR. BLANEY: Similarly, on the natural gas side, turning to page 20, the natural gas supply structure in the integrated planning model is developed from ICF's North American Natural Gas Analysis System. The NANGAS model has descripted an analytic capability that allows assessment of gas resources in markets from reservoirs to burner tip, working from a database of more than 17,000 U.S. and Canadian natural gas reservoirs.

So the point I want to make at this point is that the integrated planning model provides an integrated assessment of the U.S. electric system, the natural gas supply and demand, as well as coal supply and demand, because we believe that you have to have an integrated view of those converging markets to develop a meaningful policy analysis.

(Slide.)

MR. BLANEY: Turning to page 23, I would like to place the model results in some context. The IPM framework estimates electric generation costs which represent about two-thirds of the total cost of providing electricity to end-use consumers. While the model includes transmission charges, it does not directly estimate transmission and distribution costs. IPM focuses on those generation costs that are relevant for short-term operations and long-term investments.

The generation costs excluded from the modeling framework are not expected to be changed by RTO policy since they already incurred and therefore are insensitive to regulatory changes, the so-called sunk costs. The main relevant costs not directly estimated by the model are for transmission investments and transmission operations. These were estimated by the research team separately from the IPM modeling framework.

At this point I would like to turn the discussion over to James Turnure, who is a principal in our firm, to talk about these scenarios as well as the results of our study.

MR. TURNURE: Thank you, John. Good morning. I also appreciate the opportunity to address these issues before you this morning.

In order to conduct an analysis of this type using simulation modeling, you have to work up policy scenarios, which are combinations of assumptions. You vary all these assumptions in tandem in a way that's designed to represent a specific implementation of a policy, in this case a regulatory policy, and I'm just going to describe briefly the scenarios that were used in the study. And of course it goes without saying that there's a lot more information about this in the study itself.

(Slide.)

MR. TURNURE: The map on slide 25, page 25 of the presentation shows an RTO configuration that was used for the main policy cases in this study. This is a five RTO configuration for RTOs in ERCOT. This is the type of critical assumption that needs to be made when you're doing this type of modeling, and there are a lot of choices to be made here.

We are trying to represent very broadly the national and regional outcomes, and we'd just like to point out repeatedly that there are much more regional detailed studies that could be done on specific regions that go beyond what we're able to do with the national model.

(Slide.)

MR. TURNURE: On the next slide 26 is a table. It may not be the most transparent table, but it shows the scenarios that were developed and the key assumptions that go into them. As John mentioned in the summary, because the Commission laid out three main types of economic benefits that were hoped for from RTOs, we decided to run scenarios that try to isolate those different categories and economic benefits, so that first column there lays out whether it's transmission, generation or demand response -- more responsive demand in a competitive market.

That sets up the conceptual basis for that scenario. Then we talk about the specific model assumptions. There's a few for transmission and a few for generation and basically one for demand response. Then that shaded bar on the top just lists out the scenarios. As John said, there was a base case that's designed as a status quo regulatory case. Then there are three main RTO policy scenarios. They are called transmission-only, transmission generation and demand response, again, following the main categories of benefit.

And then two sensitivity cases, one with larger RTOs and one with smaller. There are maps of those in the study as well. I am going to talk about the results after I describe how we get from the base case to the model scenarios, and I will talk about the sensitivity cases at the end.

I just want to mention briefly slide 29, page 29.

(Slide.)

MR. TURNURE: This is called map model calibration. It's a bit technical, but it's a kind of key step when you're talking about having a base case that represents inefficiencies in the market today, you have to worry about having a model that is an optimization model which is creating an efficient outcome if you leave it to its own devices.

This slide about model calibration simply describes the process that's explained in more detail in the study in which we actually have to use the model to simulate an actual base year, in this case the year 2000. So when we get the model to replicate the actual regional generation patterns that took place in order to mimic how the NERC data came out from the year 2000, what that means is we actually have to constrain the model. We have to limit it, because the model will want to put cheaper power into some areas than in others so we actually have to create the barriers to trade that represent the current system inefficiencies. After we do that, we then move on into policy scenarios in which RTO policy is assumed to solve some of those interregional transmission barriers and a few other benefits to the economy.

So I'm just going to turn from that to results. And I would go up to slide 32, page 32 of this presentation.

(Slide.)

MR. TURNURE: And just describe briefly what happens in the model when you change the assumptions. Basically, there is physical and economic representation of the electric system in a model of this type. So when you reduce the transmission barriers, the hurdle rates between regions, this effects the pattern of interregional trade in electricity.

These changes occur over very large areas of the country. Analyzing these effects requires analytic tools with national scope. You can analyze the Northeast in isolation, but the Midwest and the Southeast may very well be doing things that affect what happens in the Northeast. That's a very key finding in this type of analysis.

In these scenarios analyzed for this study, we found fairly significant interregional trade flows that occurred over the large areas of the United States, in particular, interregional trade shifts towards Florida in the Eastern Interconnection and California in the Western Interconnection. These are major demand centers which are higher priced export regions. So the regions that can get there with electricity do their best to do so.

In the Eastern Interconnection, these shifts in regional generation and the larger interregional power flows change the export pattern of Midwestern regions away from the Northeast and towards the Southeast. So areas that are currently exporting into PJM and points north and east of PJM wheel around and ship power instead south, primarily through TVA and other areas and southern into Florida.

That's a pretty large change in the way power flows in the Eastern Interconnect. In the Western Interconnections region throughout the interior West export more power towards California. This includes Arizona, New

Mexico, the Rocky Mountains, Montana. There are maps of these flow changes in the study itself.

(Slide.)

MR. TURNURE: On the next slide, page 33, as I mentioned, there's both physical and economic representation of the system in this kind of modeling. So when the power flows change, the economic outcomes change also. Increasing the opportunities for interregional trade allows regions with lower production costs to export more power and displace higher cost production in importing regions. At the same time, changes in the assumptions that describe generators and market efficiencies also result in economic changes. For example, changes in reserve margin requirements and interregional reserve sharing can result in deferral of new plant construction to meet reserve needs.

This reduces capital investments, results in production cost savings. The impact of economic changes is measured in two ways in the IPM -- integrated planning model -- framework. The model estimates both production costs and wholesale energy prices. While these two measures usually move together, they do not always coincide. In some regions, changes in interregional trade create energy price effects that are greater than the efficiency savings and production costs. That is to say, you can have the production costs go down in some areas while the prices move in the other direction. In other regions, the reverse is true. It all breaks down to the specifics within each region.

(Slide.)

MR. TURNURE: On the next slide on page 34 we have a table of the results of the three main policy cases. The study timeframe runs from 2004 to 2020. We have here represented the production cost savings in these three different cases. I'll get to the energy prices in a moment.

This represents the base case production cost, which is the total of incremental going forward capital fuel fixed and variable operations and maintenance, as John mentioned earlier, and then the changes from that in the scenarios that we ran.

As you can see, there are three main policy scenarios. And there's a summary of these on the next slide on 35.

(Slide.)

MR. TURNURE: I think that you can look at these numbers -- you can slice these numbers several different ways. We've got both the savings in absolute dollars and the percentage savings in production costs. One way to look at it is to take a representative year, such as the year 2010. By the year 2010, most of the policy changes, most of the assumptions have taken full effect in the model, and you're seeing most of the changes you'd expect to see in these cases.

As you can see in that first transmission generation, which again combines some generation efficiencies with transmission efficiencies, savings in 2010 are in excess of $5 billion per year. These savings increase over time. That gets you into the neighborhood of 5 percent savings in production cost terms for that scenario.

We also have other scenarios with other results. We have the transmission-only case, which has no market improvements that lead to generator or demand response savings. As you can see, those production cost changes are considerably smaller in the year 2010, slightly over $750 million per year, although again increasing over time. Those percentage savings are less than 1 percent.

Another way to look at these -- well, first let me summarize the demand response case. The demand response case really includes all the benefits that the Commission has been looking for in these policy contexts. It's important to note that more responsive demand is a very important economic driver. And the way that we've dealt with that assumption we can discuss if you have questions about that.

If you add that into the generator savings from the other scenarios, you have in 2010 savings in excess of

$7.5 billion per year, rising over time. And that gets you into the 7 percent range in production cost terms.

I will also just note briefly this net present value calculation on the table. It's the final column there. That's where we take the total change in production costs over the whole study period, the whole 20-year study horizon, and we take a discount rate to that and we add it all up. And as you can see, those range fairly widely from as little as $6.2 billion in the transmission-only case for the whole study horizon, up to as much as $60 billion over the study horizon for the demand response case.

So that's the production cost side of the results.

(Slide.)

MR. TURNURE: If you turn to slide 36, there's a map on slide 36. As I mentioned, the model calculates production costs. It also calculates energy prices, wholesale energy prices on a regional basis. This map is base case status quo energy prices in 2010. It's a point of reference. Modelers use this to determine if they think the results are reasonable. They wonder why it happens. We're just showing you this as a comparator, and you can see prices ranging from a little under $30 per megawatt hour, as high as $40 per megawatt hour throughout the country, with

Long Island and New York being highlighted there in that little zoom up of the Northeast. They're the only regions in the highest cost category.

(Slide.)

MR. TURNURE: The next slide then is the relevant slide I think. It's the one mislabeled 28, but it's the one after slide 36.

(Laughter.)

MR. TURNURE: And it has energy prices change from base case in 2010 in percentage terms. These are the kinds of energy price results that occur in these RTO policy cases. As you can see, there's a variation between regions. We have a variety of explanations for this that are really laid out in the study, but if people want to discuss the explanations for specific regional results, we can try to do that within the limits of time today.

Most regions experience price declines in these cases. Generally speaking, the price declines in 2010 in this scenario range up to 10 percent or so. I'll point out a couple of specifics in this instance. We have the Southeast having a price decline taken as a whole of 4.7 percent in 2010, and we have the Pacific Northwest taken as a region experiencing a price decline of 5.8 percent in 2010. So many regions experience price declines in excess of 5 percent. Many regions experience smaller price declines, and a few regions experience price increases. The price increases, as you can see on this chart, are in a few percentage points generally speaking. We occasionally see in some regions in some years price increases that are larger than that in percentage terms.

In general, these price increases diminish over time. In many cases they disappear in later years of the study. But we wanted to highlight this as an important phenomenon that can occur when you make these kinds of assumptions in this type of analysis.

I'll just quickly go through the sensitivity cases on smaller and larger RTOs. This will be slide 40.

(Slide.)

MR. TURNURE: There's another table on page 40 of the presentation. As we mentioned earlier, there were two sensitivity cases that took into account larger and smaller RTOs. Again, these are laid out in the study and there are maps and all that sort of thing. The larger RTO case is a three RTO scenario, where you have one RTO in the Western Interconnection, one RTO in the Eastern Interconnection with Texas ERCOT left as its own RTO, so three.

We also have a smaller RTO case which is considerably more broken up. There's nine RTOs in that case, three in the West, the existing ISOs in the Northeast left by themselves, Florida left by itself and ERCOT left by itself.

The difference between these two cases is illustrated on this table. As you can see, the difference is significant, it's there. It's not nearly as large as the differences between the other cases. These differences in production cost terms generally are on the order of one to three hundred million dollars per year. This again illustrates the difference in changing only transmission assumptions when RTO scope is changed. If there is a stronger link between the size of RTOs and market efficiencies, generator and demand response, then the impact of this type of change would be much, much larger, the impact of smaller and larger RTOs. If we don't have that linkage established, this is the sort of result you get. There is still a benefit from having larger RTOs, but it's not nearly as larger as market efficiencies on their own.

(Slide.)

MR. TURNURE: Briefly on slide 43, a little bit about RTO startup costs. I think to say that they're uncertain is really the bottom line right now. And the Commission may very well be able to improve the uncertainty range with further research.

We developed a number of indicators for existing ISOs with the information that's available to estimate how you could compare them in cost terms and where you might extrapolate to if you expanded ISOs and RTOs across the country. We considered cost per installed megawatt of generation, cost per megawatt hour of power generated, cost per customer, cost per square mile of territory, cost per network node, a number of different cost indicators.

Based on these indicators, we worked off the model but in basically spreadsheet analysis to work up a set of cost estimates using existing costs and extrapolating those across the country. We ended up with an average low cost estimate of $1 billion for RTO establishment and a high cost estimate of $5.75 billion. These are of course one-time costs, although you may imagine them being amortized or paid over time, but they're not recurrent. They're essentially one-time costs to be netted against the recurring annual economic benefits of the RTOs once they are established.

We made the assumption, just to touch on that briefly, that operating costs for RTOs are a net wash. They're neither a gain or a loss in this analysis, simply because the relationship between potential saving from consolidation of existing control areas and operations and the potential need for increased functionality on the part of RTOs is highly uncertain at the present time. And we simply felt that we couldn't adequately or accurately characterize one way or the other which of those would be the greater influence.

(Slide.)

MR. TURNURE: So to conclude, slide 44, under the analytic assumptions considered in this analysis, net economic impact of RTO policy will be positive even if RTO benefits are toward the low end of the range while the RTO costs are at the high end.

If RTOs lead to improvements in market efficiency and incentives for generator performance as modeled in these cases, net benefits will total tens of billions of dollars over time. Improved demand response would likely add to these savings even further, resulting in 20-year savings of over $60 billion in that demand response case.

While there are production costs, net benefits to RTO policy is analyzed here. The regional energy price impacts vary. Most regions show price declines. A few regions show small energy price increases, although these tend to diminish over time. This in turn raises equity and revenue distribution issues that go beyond the scope of this study, because regions where local prices increase should also realize gains in export revenues, a point which we can elaborate on if you wish.

Changes in RTO scope is examined in the larger RTO and smaller RTO cases can result in larger economic benefits. The economic importance of RTO scope, however, appears to be much smaller than the effects of improved market efficiencies. Possible linkages between RTO scope and market performance would make RTO scope and configuration more important.

And there is a concluding slide on 45 on uncertainties and further analyses.

(Slide.)

MR. TURNURE: This is just to make the point that this range of potential costs and benefits is quite broad. It may be possible to narrow this range of estimates with further research and evidence. It's unlikely uncertainties can be eliminated in this type of forecasting.

The most important uncertainties for this analysis are the extent to which RTO will lead to improved market performance and the need for extensive infrastructure investments in order to establish RTOs. Better market performance would increase the policy's benefits, while reduced RTO infrastructure investments would minimize costs.

Regional variations in economic impacts appear to be an important aspect of this regulatory policy. More detailed regional analyses could be performed, including more sensitivity analysis, to show how market fundamentals and regulatory decisions can change regional impacts.

Similarly, further national level analysis could suggest more detailed information about how RTO configuration affects the results and allow for sensitivity analysis of key modeling assumptions such as demand growth and transmission availability.

And with those caveats, I will conclude. Thank you very much.

CHAIRMAN WOOD: Thank you for that presentation as well. One of the things that came out I guess at this last page and also from my review of the study last night was focus on the key assumptions. And the executive summary of the study itself observed that several key assumptions are actually conservative in the policy scenarios, and I guess I wanted to explore with you all on the record some more detail about the assumptions, and particularly in light of what you laid out on page 45.

What exactly, in some more detail, would be the type of assumptions that you chose to be conservative? What would be an example of that?

MR. TURNURE: Well, Mr. Chairman, the term "conservative" is of course somewhat subjective. One thing that is noteworthy in this study was that given the timeframe of it, we made a decision to stick with existing analyses to the extent that we could. We are sticking very close to some types of work that was done for national studies before, both for the FERC and for the Department of Energy. The Department of Energy has done studies of, for example, the Comprehensive Electricity Competition Act a couple of years ago. There are similarities and differences in these studies, and some of that is discussed in the report.

We tried not to go developing new types of research and doing novel innovative approaches with the model itself. If I were to pick an example of an assumption where -- you can discuss whether it's conservative or not, but it certainly fits within a field, a research field, it would be the demand response approach that we have adopted for this study.

As you can see from the study results, it's a very important assumption. We describe this in some detail in the report itself. We decided to make an assessment of demand response across the country, region by region. And the way we did that was by assuming, for example, that only one half of customers would actually be in demand response programs or be exposed to prices such that they would respond. So it's only half of the customer base to start off with.

Secondly, we applied a very small price elasticity, price response of .1, which most analysts, most economists would assess as a short-run price elasticity. That is to say, longer-run price elasticities mean customers have time to change their capital, change their appliances, change their equipment, change how they do things, whereas a short-run elasticity is strictly a behavioral response with everything else fixed.

That gives you a demand reduction on the order of 3.5 percent. Now a 3.5 percent demand reduction under many analyses that I've seen and can point you to is not a difficult number to reach. If you want to call that conservative, you can judge that for yourself. There are other examples of this type. John, do you want to add something?

MR. BLANEY: Yes. I would like to add that another way in which the results of our study could be construed as conservative by some is the fact that our results show on average wholesale price decreases ranging from 3.5 to 5 percent in the RTOs that we examined in 2010. But we have not examined the sort of macroeconomic benefits that could accrue from those price declines. And that's another way I think because of the narrow scope of the study that one construe the results --

CHAIRMAN WOOD: Like more jobs or more tax base, et cetera?

MR. BLANEY: Exactly. Yes.

CHAIRMAN WOOD: On the other end, are there any -- I hate to use the "L" word -- but are there any more liberal assumptions that fit here that kind of on the other end that may be a little on the high side?

MR. BLANEY: I think that the assumptions that we've made here are consistent with previous FERC analyses as well as other studies going back to FERC Order 888. And so I think that in that case, the assumptions that we're making are in that family, that mainstream of consistent analysis.

COMMISSIONER MASSEY: When we issued Order number 2000, one of the benefits that it cited of large RTOs is the reliability benefits. Did you focus on that at all in this study, or was it simply the cost question?

MR. TURNURE: Well, it's an economic study, and the scope of it was basically the economics. Of course, reliability and economics are intertwined. And you can look at that in a number of different respects. If you consider the transmission efficiency assumptions that we made, some of them are reliability related. In particular, the ability of broader RTOs to more effectively share reserve capacity and impacts on reserve margins, making reserve margin requirements less because the regions are bigger, those are effectively reliability savings. It costs you less to buy the certain level of reliability that you're looking for.

We did not analyze line-specific and engineering power flow types of reliability such as a very detailed look at congestion management, for example. That was not in the scope here. And in technical terms, it's possible you could argue that if there is an outage, there is a cost to that outage. And if you assume that you may avoid outages from better reliability management, you could potentially have an economic cost or benefit here that's not included.

This model, because it's long run, tends to not look at very short-run interruptions of that sort.

COMMISSIONER BROWNELL: I have a couple of questions. You talk about the costs and the range of potential costs for startups. Would a standard market design reduce those costs and bring some certainty?

MR. TURNURE: Well, the range of startup costs is very broad because the experience of ISOs has been very broad. Presumably, standard market design may narrow your assessment of these costs, put you into a narrower range. Where the infrastructure needs and the functionality comes out will really dictate whether you're on the lower or the higher end of that range ultimately. But presumably, if you had a better road map for how the RTOs would be actually putting their footprints down, you'd have a better sense of the kinds of costs you'd be looking at. So, yes, certainly.

MR. MILLER: Excuse me for a second. I think one of the things that I don't know that in doing an overview that we mentioned was one of the assumptions -- and I think Jim refers to it as market efficiencies -- that implies that there is some form, and it doesn't sort of say what, but there's some form of a standard market design so that you allow for movement of power. That's sort of one of the key underlying market efficiencies that you get. And it's an assumption in the study, isn't that, Jim?

MR. TURNURE: Well, the model clears regional markets as efficient pools, so that effectively does assume that they're all operating in the same fashion, yes.

MR. WHITMORE: As I understand it, the estimates of the costs here include all of the experience so far including a lot of learning pains that people went through in various parts of the country like California and so forth. Presumably, both the standard market design and the simple process of having learned what works and what doesn't work and having some software that's already done and so on and so forth, I would think would lead you toward the lower end of the range, although I think Jim's exactly right, that if you put in a great many requirements as to exactly how the market has to work that we haven't thought of yet, for example, that would add cost.

But as a general matter, with any of these things where it's a new thing, costs would I would think tend to come down over time.

COMMISSIONER BROWNELL: And we make no attempt to really evaluate the efficiencies that you would get, as you mentioned, from consolidating existing functions, which I think was a pretty positive experience in Texas in ERCOT.

Let's talk about those areas where it looks as if there are not obvious benefits. First let's talk about some of the other impacts that you discussed in terms of greater returns on exports, for example, and talk about the transient nature in some of the areas, that it's a short-term phenomenon.

MR. TURNURE: Well, what you see in some regions is a race, if you will, between production cost savings and exports of less expensive supply leading to some moderate price increases in those regions. It just depends how that region's supply happens to be configured.

And so I'll take the transient part first. It's simply the case that in many regions over time, generator savings and production cost savings dominate and overwhelm those export effects and it just takes a few years for that to occur. That's why the price increases go away in most regions.

Even in the areas and the years when there are price increases, it's important to keep in mind that these regions are all experiencing production cost declines. And what is going on is that they're exporting power to a higher cost region and therefore realizing the revenues from that coming back.

Now some analyses, some economics would argue that that is a simple producer-consumer surplus situation. Either the consumers get it or the producers get it. That's not necessarily the case in complicated regulatory industries that are in transition. We would prefer to think of it as earnings, earnings, if you want to call it beta or some other technical earnings term.

What happens to earnings once they get to the generators is not clear. There are a number of aspects to this. One is economic development, employment-type aspects in the region, which would presumably be of benefit to that region. Another is taxes. Presumably there are tax benefits that accrue to the region as well. And thirdly, there may very well be equity or revenue distribution of the earnings, particularly if it's a vertically integrated system. That of course is more of a state matter at the present time.

So there are a lot of different aspects of that, and to trace through all those revenue flows will require considerably more effort than we've had time to do here, and it operates at such a detailed level and such a regional level that it was considerably beyond the scope of this exercise. But conceptually, those are the sorts of issues you'd want to consider if you're in a situation like that.

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COMMISSIONER BREATHITT: I have a couple of questions. One is focused around a figure that was stated at the end of the presentation, that by the ear 2010, it's likely that there may be three-and-a-half to five percent savings in wholesale prices.

Can any of the results or data be extrapolated down to retail customer savings? I know this is focused on RTOs and the wholesale side but can some people who are more used to reading through these reports and assumptions more than I am be able to take this further to say what it means to the retail level?

MR. TURNURE: Well, it's a type of analysis that I've seen done a few times. The Energy Department's analyses, because they're more focused on retail competition, try to take things down to the retail level and have that kind of price impact. There's a number of complicating factors if you start looking at the data on who's getting what kind of prices. The short answer is, it would be a bit of a struggle to do it, and I would be tempted to leave it as an exercise for FERC Staff.

(Laughter.)

MR. MILLER: Thanks a bunch, Jim. I really appreciate that.

(Laughter.)

COMMISSIONER BREATHITT: So what we need to do is look at this purely as the results from savings and costs associated with merging markets and going to larger RTOs?

MR. TURNURE: There's a number of other aspects of competition policy if you want to put it that way. This is designed as an analysis of wholesale impacts of RTO policy, as the Commission has described it, and that's the scope of this analysis. We were trying very hard to stay within that scope and to put that in perspective. So I think that it's just up to everyone else now to take the results and make their own judgments.

COMMISSIONER BREATHITT: And take from it. Well, that leads me to another question I have which is, why would it be important to understand. I come from a coal region. Why is it important to understand the coal and gas part of this study that you described earlier?

MR. BLANEY: I think it's because in today's market, the coal/natural gas markets, as well as the electric market, and even more so with the environmental markets, air regulations, those marketplaces are converging. We don't believe that you can look at the wholesale power market in isolation without understanding how the coal markets function because the principal variable cost component of electric generation is fuel. So we believe you have to have an integrated perspective on coal markets, natural gas markets, wholesale power markets, as well as environmental regulations in order to do this kind of analysis.

COMMISSIONER BREATHITT: It even included representation on coal supply/demand and transportation. How do you get the coal to the power plant.

MR. BLANEY: Yes. The costs associated with that as well. Every coal plant in the model is assigned to one of 41 different coal demand regions which are distinguished not only by location but by mode of delivery, so we're doing a very careful job of that.

COMMISSIONER BREATHITT: So all that was factored in at 3.5 to 5 percent potential savings by 2010?

MR. BLANEY: Yes, Commissioner.

MR. MERONEY: I'd like to point out, Commissioner Breathitt, that that question is right on point for these people. Your state of Kentucky is probably represented in this model in order to be able to show the big differences in the way coal works in eastern Kentucky and the way it works in western Kentucky. So we're bringing these kinds of key details into this analysis.

COMMISSIONER BREATHITT: I have one short final question. You probably have more. On page 34, you talked of -- not the report but the summary -- the transmission-only case showed under a one percent savings from the base case. You mentioned that the production cost savings are lower with transmission-only. What would production cost savings be with transmission-only? Would it be maintenance or upgrading a line to produce production?

MR. TURNURE: It's actually the ability of the model to share capacity and reserve margins and that sort of thing. It can be the case that if a region in the base case would need to build a unit, a new generator to meet its reserve requirements, if it can share better across the grid because of the transmission improvements, it may be able to defer that unit and save the capital costs associated with it. There are some other effects too involving the interregional trading.

MR. BLANEY: You also have in that case the assumption of the removal of the barriers that exist today towards free and open access to the transmission system, and so you see power flowing from low cost regions to high cost regions that would make sense on an economic basis that is not occurring today.

COMMISSIONER BREATHITT: The savings in the transmission and generation cases are much larger, so I was just interested if the transmission-only scenario was a smaller component of the savings?

MR. BLANEY: Yes. That stems from the results of our study. In the transmission and generation case, we are positing, as the Commission has, that these transmission improvements, this opening up of the transmission system, provides stimulus to the generators to be more efficient in their production of electricity which then leads to lower cost improvement in the efficiency the heat rates of the units, as well as improvements in their availability.

CHAIRMAN WOOD: Buddy, if Marilyn or Michael are on the phone, if you all want to pipe in or Commissioner Atkins or my colleagues or Staff, this is the open forum.

COMMISSIONER MASSEY: I have a question. I'll pose it later because I want some of the state commissioners to have an opportunity to comment here, but it's going to relate to TVA and where they fit in this study. Let me just defer that for now.

MR. ATKINS: Mr. Chairman, thank you. I did want to go I guess on the summary of the output. I think it's page 23 although I had some of the pages were messed up. But placing model results in context, in particular the third bullet there, the main relevant cost not directly estimated by the model or for incremental transmission investments in transmission operations, and those were estimated separately. And we know, I guess, or at least I do, having the advantage of sitting in with you folks on the advisory group, that the optimization routine still with the generation component, then you add on the transmission to that. Given that, I'm wondering if you can go to your report, and on page 36 of the report, down near the bottom where it talks about policy scenario specification, and in particular transmission transfer capability expansion, trying to tie all this into the idea of transfer capacity, did the modeling that you all conducted within IPM include considerations of native load? In other words, if we can include native load considerations, those simultaneous or non-simultaneous, whichever scenario you look at, transfer capabilities between regions can become much lower than either the total or the actual.

How do you -- Jim, if you could just talk about that a little bit, and then how you got to some of these conclusions since this is an RTO study, and given that the outcome of just the RTO-only shows less than one percent benefit.

MR. TURNURE: The role of native load in contracts is a very problematic area for this type of modeling. Essentially you have to make some judgments or assumptions about whether or not native load or contract terms or treatment makes the dispatch of a region less efficient. If it doesn't, then you can run a model like this that can clear using efficient dispatch as a pool, and you get the same result.

If you think that native load and contract requirements are doing things to dispatch that are different than the least cost result would be, then you have to do something about it in the model by changing assumptions. Now we have sometimes done that. We often do it with contract requirement generators, you know, PURPA requirements type contracts for instance, that actually require certain generators to run.

Doing it for native load on a broad scale, however, we typically don't do -- we would need to have some reason to do that, some direction, some particulars. It's an issue which was raised by a number of commissioners at the state level. Their concerns were typically about reserving their low cost generation for native load use. That gets you right back to the same problem which is does a native load restriction of that sort really interfere with efficient dispatch, or doesn't it?

We considered a few ways to model that and I can discuss that with you now or off-line or whenever, but it gets very complex. You have to do things like add sets of dummy regions over the existing regions to put the restricted units in there and keep them from playing on the export market. That leads to inconsistencies between runs. So we had a hard time with that.

MR. ATKINS: I guess in general just looking at I guess it's page 34, but the various cases looking out 2010 or 2020, it would seem that the RTO is trivial and unimportant, and it would seem what was important would be generation efficiency and demand response. Is that unfair?

MR. MILLER: That's one of the reasons why the FERC policy in the study is the sort of lead on this. It's the presumption in both Order 888 and Order 2000 and all FERC policy that efficient operation of the grid and the ability for all generation to play in terms of non-discriminatory open access leads to more competition. If you have access to more markets, then you're competing against more generation, and as a consequence, you have an incentive to lower your costs so it feeds off of the presumptions, and that's why we lead off with all the FERC policy statements on that.

MR. ATKINS: Let me ask one more question, and that'll be all. Just again for reference, when I have a demand scenario in an aggregated area, whether it's a NERC subregion or a whole regional RTO. In order to meet that demand, I'm going to place generation there that's least cost, and then any residual or leftover would be exported. So I'm going to meet my aggregated area's demand first, as a priority. It seems like getting back to some of the initial scenarios and assumptions is key to making sure that we understand.

MR. TURNURE: I think John or I could actually address that. The model is trying to minimize costs across the entire system. So each region has to meet its requirements. But it may have other resources available from outside its region. In that case, it may be more economic to not build a unit in your own region but rather to rely upon some existing capacity outside the region. Over a long period of time in a model like this, what dictates the way people build has to do with things like gas transportation. It may be cheaper to build a combined cycle plant in the next region over because the gas is much cheaper for pipeline reasons, and then ship the power across. There are some variations like that that go on here. Every region does need to meet its own requirements, though, but the model is not optimizing each region as a separate little decision agent, if you see what I'm saying; it's optimizing the whole system.

MR. ATKINS: Thank you.

CHAIRMAN WOOD: Let me follow up on that. In the three scenario versus the smaller and the larger, and I guess the base had five, right, so you've got three, five and nine, with not a lot of spread between them. What does explain the little bit of spread that there is? Is it that you're optimizing within a larger region first? To follow up on Buddy's question, that in the three, you're optimizing within the whole eastern interconnect?

MR. BLANEY: In doing that, Chairman, we are assuming that within an RTO, there are no transmission inefficiencies or charges over and above tariff that would be required to move power within the RTO and so you're able to more fully optimize the generation of power to meet demand across that whole RTO area subject to the transmission capacities that link the physical system together.

CHAIRMAN WOOD: So the reason why the nine is a little bit higher than the five or the three is because of some rate pancaking for transmission?

MR. BLANEY: Yes, that's one of the factors, yes.

CHAIRMAN WOOD: What would other ones be? Would that be the main one?

MR. BLANEY: That would be the main one, yes.

MR. MILLER: And that's based on the assumption that all the benefits in the smaller or larger scenario are transmission-only benefits. If you make the assumptions that they also will lead to other market efficiencies, there'll be other benefits.

CHAIRMAN WOOD: That's consistent.

MR. MERONEY: Just to follow up on that, it's probably clear but it basically means that your reference point for two or three hundred million dollars of benefit related to larger rather than smaller RTOs should be the benefits that you see in the transmission-only scenarios, so it's two or three hundred versus seven or eight hundred million rather than five billion. So in relative terms, the impact of size is not as small as it might appear at first glance.

CHAIRMAN WOOD: Folks joining us on the phone, if you all want to pitch in anything. You all still there? Marilyn? Michael?

MR. MILLER: While we're waiting on that, Commissioner Massey on one of your points?

COMMISSIONER MASSEY: I notice on page 25 that your base assumption is five RTOs. I notice that you have TVA in the southeast RTO. Also your study showed that there's going to be a lot of power flowing to the southeast through TVA. I'm wondering, I'd just like to have any comment you'd like to make on where TVA fits in this scheme, how important is it for TVA to be in the RTO? Don't a lot of these power flows come through TVA? What if TVA isn't operated as an open access RTO-type system, what happens?

MR. TURNURE: I would just comment on some of the results and some of the effects that we saw when we allowed the flows to optimize in the southeast particularly. You're quite correct. Again, there are transmission flow maps in the study for this very reason. There's a fair amount of power routed through that region. It's not the only route that power takes down to the south, it also routes through

Duke and Entergy and other places. But you know, TVA, if it's available for a throughway is something that the economics would dictate would be used. Where that fits in the policy context is of course not our responsibility per se. You could do more regional work. You could reconfigure these RTOs and take a look at what happens if TVA is or is not as available as it is in this case in which it is available. That's the kind of follow-up work and more detailed work that could inform some of these discussions.

I'm not sure if Staff has any comments on that.

MR. MILLER: I think it's important to think about the way that we see power flows today. For whatever reason, TVA is a fairly difficult path to get through, and what you see is that power will still try to get to the south and to Florida. It will just have more difficulty getting there which could lead some reduction in benefits. Having TVA out would definitely be a net loss, I think, but we'd have to do some more analysis to really quantify that.

COMMISSIONER MASSEY: So we don't know what level of that loss it would be until we have more analysis on that?

MR. MILLER: No, sir.

COMMISSIONER BREATHITT: By TVA out, do you mean out of an RTO?

MR. MILLER: Right, operated the way it is today.

MR. CUPINA: Mr. Chairman, may I ask a question. Jim, in what you described as initial, non-recurring start-up costs, $1 to $5 billion I think, what are the components of those costs? Are they mainly software and organizational type costs, or are they also additional transmission capacity?

MR. TURNURE: The components of RTO start-up costs that we were looking at are actually kind of a different category mostly. There are logistical, operational, labor, and software sorts of costs, but rather than transmission infrastructure, a large cost category you run into is other kinds of infrastructure, essentially communication infrastructure. Control rooms, do you build one or not? A new one? Do you replace your existing control areas with a new, dedicated operating center? And what kind of communication infrastructure do you need to get the computers and the commands out to the power plants that you're controlling from there, i.e.,. do you lay in dedicated fiber optic, do you use existing phone lines, that kind of thing. That infrastructure, hard physical infrastructure is a real big driver.

CHAIRMAN WOOD: Ed, do you want to talk about the next steps?

MR. MEYERS: Thank you, Mr. Chairman. Today's of course the first opportunity to discuss the cost benefit report. There are many more sessions to be held down the road. For example, between March 4th and 15th, we will be holding regional teleconferences for every region with the states on the cost benefit study. This will give the state commissioners a full opportunity to explore all the issues and the consultants ICF will be in on those calls.

There will be similar teleconferences with the other parties as well. Of course, for these teleconferences, we will be following all the noticing and transcription procedures as outlined in the November 9th FERC Order. There will be a formal comment and reply comment period to be announced today, and also down the road we will be holding regional panels. These are the state/federal regional panels established by the FERC. These will be out in the regions in the spring and the summer and needless to say these cost benefit results will be very much the topic of these regional panel meetings, along with many other issues. So this is the first day of many.

COMMISSIONER BROWNELL: I'd just like to add our thanks to the consultants and the Staff who worked under some grueling deadlines, and probably would have done a whole lot more had we given them time. I think this report provides a great platform for us to have an informed and rational debate about where we need to go, and while there may be further questions, and I certainly look forward to working with our state colleagues and others in the industry, I think we have a terrific start here, and one of I think the enormously positive aspects of this is a confirmation of what we heard during RTO week, and that is demand side management must be part of our market as we move forward. This simply is good evidence that supports what I think almost one hundred percent of the participants in our RTO sessions have said, so a great start, a great platform. I look forward to a really informed dialogue going forward and perhaps more questions, but it's great to have this.

Thank you.

CHAIRMAN WOOD: I want to add to that. I look forward to digesting the report that we got yesterday in more detail but appreciate the time and effort you all spent today and certainly throughout the process, I would say I think I share on particularly the demand response issue I guess in my mind, that was kind of a big unexpected I think you expected it would have been better than not being there at all. But I think what I would agree is a relatively modest assumption, how that plays through in the numbers and allows for local demand or load to respond to the market signal, not an outrageously high market signal but just a traditional market signal of normal peak summer days is pretty noticeable. It was a good 50 percent more savings than the base case of transmission plus generation dispatch in the 2010 scenario which was kind of what I looked at. Once it's all in and operating, what do we talk about as far as benefits here. So I was intrigued by that finding and look forward to seeing if there are parties out there that think it was either too conservative or not conservative enough because that one, from our session that we had on the 14th, with the DOE co-sponsorship on demand response, participation in the market seems to me to be an unmined gold mine for customers and I sure liked seeing that.

I think the generation case, as I think Buddy was asking through some of his questions, is certainly one I want to understand better what the difference between the stripped down and the middle case was, those generation efficiencies, those are achievable. I think we'd like to test that but those are the two things that I plan to spend the bulk of my focus on as well as any issues that parties may raise during the vetting process that Ed laid out.

I certainly want to make sure that despite my personal belief that RTOs are good, I think we've got to base our further decisions on a good record and I think today was definitely a good start on that and I know parties on both sides of these issues are anxious to either get going or go somewhere else. But I think we are committed to doing this in the right manner. I do appreciate, and I remember so clearly back from October when a lot of our colleagues, and Buddy I think you were in the audience taking it all in, and that's when you and I first met, but in October when our colleagues were saying, look, do this based on the record, you haven't been at the state level, everything that you do gets based on the record because courts are going to review it anyway. That was a real sound piece of advice. I'm glad we took it and I hope we continue to work in a collaborative manner to pull these together, but it will take a little bit longer than just rushing through, but I'd rather be right than fast.

Thank you for helping us in our effort to be right.

COMMISSIONER MASSEY: If I could just comment as well and wrap up, I appreciate that this is a conservative study; it doesn't look at the world through rose colored RTO glasses. There are overall benefits but you're careful to point out that there are slight price increases in some regions. Some of these are temporary but you don't gloss that over at all. I think this is a very credible effort to put some numbers on our RTO policy and I thank you.

COMMISSIONER BREATHITT: I do agree with everything my colleagues have said. For me, this is the first blush and I appreciate the summary and your walking us through that. I think it will unfold in the next months to come and I look forward to hearing how everyone analyzes this for themselves and the nuggets that they take from it. It certainly was a good idea when the state commissioners, at our first RTO week, asked us to undertake this assignment. We've got some NARUC folks on the front row, so I look forward to having the benefit of a lot of collective thinking and also going into this in detail for myself as well. Thank you.

CHAIRMAN WOOD: Okey doke. Thank you all very much.

(Pause.)

SECRETARY SALAS: Mr. Chairman, Commissioners, the next item on your discussion agenda this morning, we will consider together, E-1 Boston Edison Company and E-14 New York Independent System Operator, Inc. The presenters this morning for these items, John Rogers with Sateev Jagtiani, Sarah McWane and Helen Manacke.

MR. ROGERS: Good morning, Mr. Chairman, Commissioners. E-1 accepts for filing Boston Edison Company's unexecuted interconnection agreement with IDC Bellingham. The Order finds that the agreement substantially complies with Boston Edison's recently accepted standard interconnection agreement on the issue of cost allocation for system upgrades. The order affirms the

50/50 cost allocation between the parties.

E-14 accepts for filing, subject to modification, the New York ISO's revisions to its interconnection cost allocation rules under its open access transmission tariff. The rules allocate cost responsibility for system upgrades necessary to interconnect new generation and merchant transmission projects. Thank you.

CHAIRMAN WOOD: Thank you. The reason I wanted to call these together is, as you know, since I've been here I've been pretty interested in this new generator interconnection cost issue. These two cases I think probably more clearly than any others juxtapose the fact that we've got a policy that we developed in I believe it was Consumers Power that I think you all voted on right before Nora and I got here. Then we talked about the interest issues and other things like that. But the core issue that a generator would pay the system upgrade costs as well as the local interconnection costs, but would receive over some future years a full transmission credit for what he paid for those system upgrade costs as being the standard policy. I think that was certainly something that I came around to and got pretty comfortable with as being to me sufficiently incentivizing for generators to locate in various parts of the country, although admittedly maybe not locate in the ideal smartest spot, but at least to locate in the first place.

Since that time, since we've looked more and more at some of these contracts that are coming up from the more organized markets in New York and New England, which are before us today, and I also understand in PJM we've got that as well, is they have taken, because they started earlier, a different approach toward allocating these costs. I know in the discussions that fell out from the ANOPR process that led to a standard interconnection agreement that I believe we'll be publishing soon for comment as a final rule, that some of the cost allocation issues do vary across the country. These are two here, I'm fine with these orders. I just wanted to say on the record that as I guess the most pig-headed one on the existing policy, if there are better ways to do it that address regional needs, which these two orders encompass, maybe not better ways but this is a way that has been successful.

Certainly the increase in construction in New England is quite noted by almost any observer. If there is a way out there that might be different from the FERC policy that we've incorporated in Consumers Power and its progeny that might be better, I'm open to that. If there may be a better fix for RTO West that's different than the one we've got here in New York ISO, I would be open to that.

And I know, Bill, you and I spoke yesterday about this, but certainly if that inconsistency causes some bad investment or bad policy outcomes, I guess I would pull back my enthusiasm for letting ten or 12 flowers bloom. I just want to say on the record, if there are regional fixes here that work, I won't run screaming from the room.

COMMISSIONER MASSEY: I might.

(Laughter.)

COMMISSIONER MASSEY: Wouldn't that be fun, wow! I just wanted to have a dialogue with you on this because, as someone who began to be a broken record about generator interconnection standards a couple of years ago, and now moving forward with standardization in that area has a lot of traction here at the Commission and it's very likely that we will finalize such a rule. And I think it will help end any sort of interconnection ledger domain that may exist but my concern with an approach that lets regional flowers bloom on the cost allocation question is whether that might somehow create some inefficiencies in the marketplace. Whether generators might choose to locate in regions that actually have the easiest cost allocation rules and whether that's a good thing or a bad thing.

I sort of thought we were trying to get away from that with the standardization process so that interconnection decisions would be based more on the economics of selling power in a particular region rather than variations in interconnection policy. So I wanted to raise that concern and say that I thought we were moving toward more of a national policy with respect to both interconnection standards, terms, and conditions, which we are, and how to deal with the cost allocation question.

CHAIRMAN WOOD: According to our schedule, we are, I just want to say here, I'm looking at the region, particularly the Boston Edison one, looking at a region that what certainly from my ERCOT glasses would not be as generator friendly. Yet New England and ERCOT are the two places where the most significant new power investment has happened in the country in the recent few years.

I'm wondering is it really more a function of the fact that you're competing against a bunch of unbundled generation that might be the most attractive reason why a generator would locate there, as opposed to a detailed pricing policy? I'm open to being persuaded that. I tend to think that it's hard for me to look at ERCOT and think, okay, was it the fact that all the old rate-based generation was cut free and sent out there to sink or swim based on how efficient it is that made new generators come there, or was it a very streamlined and standardized generation interconnection policy, or both? Probably some part of both.

New England similarly has unbundled a lot of generation and it's out there to sink or swim on its own and some new generators come up there knowing that they'll actually have a fair shake and not have to be hobbled by one foot being broken before they start the race. Did that have a lot more do to with it than the pricing policy, or did the pricing policy, was that kind of immaterial? I know they moved from 50/50 to 100 percent now.

So I'm open to being persuaded on that but I note, with interest, that we do have in some of these more organized markets that we've looked at, as being wholesale market leaders, that there is some difference from the policy that at least up to now I thought was really a no-brainer. If there's a case to be made why something other than full revenue credits back to the customer works, certainly we heard that from the PJM parties during the ANOPR process. Well don't touch, don't trump our deal.

MR. LARCAMP: We didn't let them talk about pricing at all. That was off the table. They tried on several occasions. I think what this points out, Commissioners, is where we have these organized markets, and I'll state the obvious, where we have very good oversight and cooperation with the state commissions that ultimately many states are required to certificate siting decisions for the generation facilities, if they are willing to move to something different in the context of those RTOs.

Typically, I don't think staff is going to be particularly troubled by that if that's been vetted. Obviously, when those rules are proposed, if the state commissions are dissatisfied, they will certainly let us know what their position is on all of that. The way I interpret that is if the regional oversight, the regional issues are things that we can work in a cooperative fashion with the states, and they're okay with it, absent the identification really of some problem that sort of is impacting the markets in general, it would be difficult for me to see where Staff would have a problem with that.

COMMISSIONER MASSEY: Suppose, let me ask this fundamental question. Suppose our standard market design incorporates a locational marginal pricing feature which essentially says that we want power to be incrementally priced. That seems to me to state a certain philosophy about the marketplace that we are trying to incorporate through our standard market design. What if you had a region that decided to socialize all interconnection costs and blunt the price signal there, blunt the market signal by socializing those costs?

It seems to me, I wonder whether that would be fundamentally inconsistent with the concept of locational marginal pricing, and if so, how we could have both say in the same region? Would that be internally inconsistent?

Would that make any sense in terms of how the market operated?

MR. LARCAMP: I agree that could be a problem, Commissioner, but I want to see how the locality intended to handle redispatch costs, for example. What you give up on the front end you can pay on the other end if you will. I think I'm just suggesting that certainly I think we should be moving in favor of giving the correct price signals but I think there is an awful lot of judgment involved in calculating how much of an expansion is needed for a particular generator as opposed to how much is needed for sort of the general system improvement?

You know, I think to the extent that we make all of our allocation decisions in one way or another tend to blunt some of the signal in some respects and it will be a judgment call. I just think that this is one that it does not bode well, I don't think, for additional infrastructure if we are not working in cooperation with the state citing authorities that are necessary for the infrastructure additions to be built.

MR. CANNON: And Commissioner, I tend to think of these interconnection costs as being more sunk costs. You can specifically assign them or you can roll them in. That does have policy implications in terms of decisions as to whether I want to site in this RTO or this RTO, but I don't see it necessarily as tied to locational marginal cost

pricing, where that's focused more on the actual running
cost of that particular unit.

COMMISSIONER MASSEY: It's not tied to it but
there's a philosophy that underlies a locational marginal
pricing scheme which basically says markets operate best and
locational decisions are best made when there's an
incremental price signal that's available in the
marketplace. And so that seems to me to be such a
fundamental philosophy of where I hope we're headed on
market design, that it seems to me that other policies ought
to be consistent with that fundamental philosophy. So I
have an open mind. Pat and I talked about this yesterday
and he told me he was going to raise this issue, so my
colleagues were aware that I would raise these concerns and
we will continue to debate it. But I did want to make a
record that I think this question of how to allocate these
costs may have national policy implications. I may come out
in favor of a national policy on this point, rather than
regional policies.

CHAIRMAN WOOD: Are you thinking in light of that
the kind of philosophical equation to LMP that that kind of
argues for an assignment of network upgrade cost to the
generator?

COMMISSIONER MASSEY: It certainly moves in that direction. I don't know whether it's all of the costs, part of the costs. I think assigning none of the costs would be fairly inconsistent with that policy, with the philosophical concept of locational marginal pricing.

CHAIRMAN WOOD: I wouldn't disagree with that.

COMMISSIONER BREATHITT: I think there is such a difference in the U.S. in terms of where production fields are, where sources of the commodity is that power new units. There's a lot of work being done on coal gasification that there are significant differences in the country of infrastructure and where sources of supply are, that I think that that needs to be factored in on where power plants are located and how they get power to market.

Power plants, the new power plants are built at risk just like a lot of the new pipelines now are being built at risk. There may be some areas where there become gluts. I would hope that it's not because of how different regions or states site power plants, or what the pricing policies are for interconnecting, but I still think that there are enough differences across the country with the infrastructure that it might be wise to let some of the thinking develop on how to price this. I know that TransLink has done a white paper. There are other white papers around on how to price new power plants and hooking them up to the grid that I would like to have the benefit of some more thinking before we become rigid and come up with something that may not fit everywhere.

COMMISSIONER BROWNELL: Just a quick comment. I'm glad actually the two of you raised this issue because I think that it does have long-term implications and we really need to get our arms around it. I'm inclined to agree with Bill's focus that consistency is very, very important. At the same time, I'm open to what might potentially be regional differences, but I was reflecting on how wide the regional differences were at the beginning of RTO week, and how they have kind of narrowed as we've discussed the issues around, for example, congestion management. So I think it behooves the parties to come in and make a compelling case that there are significant differences, and I wonder how many variations on the theme the market can tolerate. So I'm glad we've raised it, and I hope that we'll get some really substantive input as we develop those because I think it's a critical part of making the markets work. And I think we've seen some implications of not having a consistent policy.

CHAIRMAN WOOD: Let's vote.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item for discussion is

E-6 Central Illinois Light Company.

CHAIRMAN WOOD: I asked to call this separately to make this one brief statement and save myself from drafting a concurrence, but one of the issues that was set for hearing here related to cost allocation. As a cost of service guy, I wanted to point out that I have long had a preference for corporate share or overhead or other outside costs to be direct assigned as much as possible, and avoid the use of labor allocators, rate-base allocators, or other generic allocators. I know that's a deviation from FERC policy, but as a former retail regulator, who saw an increasing number of costs come through to over 40 percent of revenue requirement costs through come through as allocated costs from a merged parent, it became very frustrating, particularly in light of PUCHA and Ohio Power to basically have to take the allocation factors as a given from the company and the SEC, who didn't really mind, but we did at the retail level in preference to a direct assignment.

I saw that issue being raised here in the transmission rates and the ancillary service rates for this company, and wanted to just state on the record that although the Commission has had some recent case history on cost allocation that is referred to in the Order, I appreciate that my colleagues were willing to set that particular issue for hearing and to allow the company to make the case perhaps that the direct assignment is preferable, so I look forward to seeing how that may come out, and otherwise in all regards support the Order.

Vote.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye.

COMMISSIONER BROWNELL: Sorry, I'm concurring.

SECRETARY SALAS: The next item on the Agenda is E-28 the New Power Company against the PJM. Commissioner Brownell is recused. Presenters for this morning on this item are Morris Margolis, Roland Wentworth, Michael Goldenberg, Michael Bardee and Katherine Waldbauer.

MS. WALDBAURER: Good morning. In this Order, the Commission denies a complaint filed by the New Power Company against PJM. New Power is a load serving entity in PJM, and it filed a complaint alleging that due to the exercise of market power in PJM's capacity markets, prices for capacity in PJM are unjust and unreasonable and unduly discriminatory. New Power asked the Commission to a) order refunds beginning 60 days after the filing of the complaint, which would be starting September 17, 2001, and b) to order

PJM to eliminate its seasonal deficiency charge and revert to its former daily deficiency charge.

For the most part, New Power relies on the events of January, February and March 2001 as evidence of the exercise of market power and PJM's capacity markets. PJM's market monitoring unit recently issued a report finding that market power was exercised in the capacity markets during the first quarter of 2001, leading to non-competitive prices during that quarter. The draft order agrees with that conclusion.

After the first quarter of 2001, however, PJM implemented two market fixes. As of May 4, 2001, PJM changed the allocation of deficiency charge revenues so as to create less of an incentive for capacity holders to withhold capacity from the market.

Second, as of July 1, 2001, PJM implemented a seasonal deficiency charge regime which first required generators to commit their capacity to PJM on a seasonal rather than a daily basis, and similarly established penalties for LSCs on a seasonal rather than a daily basis, making those penalties more deterrent.

Since July 2001, prices in PJM's capacity markets have fallen to near zero and have remained there. New Power has not demonstrated that prices in the capacity markets since that time have been excessive or that discrimination exists against new LSC entrants. The draft order therefore denies New Power's request to order PJM to eliminate its seasonal deficiency charge.

PJM is already conducting a review of its capacity reserve markets and the broader issue of generation adequacy is being addressed in the Commission's on-going proceeding to develop a standard market design.

Finally, New Power also seeks refunds for alleged overcharges but refunds would only be available from September 17, 2001 onward, and since daily capacity prices have been at or near zero from that time forward, no refunds would be due for that period.

CHAIRMAN WOOD: Thank you for that. I have nothing to add. I support the order.

COMMISSIONER MASSEY: I do have a question. I think you said that the order agrees with the market monitor that there was an exercise of market power during the first three months of 2001?

MS. WALDBAUER: That's right.

COMMISSIONER MASSEY: But our order concludes then that it is unlikely that there could be future exercises of market power because the market the defective market rules in the ICAP market have now been corrected.

MS. WALDBAUER: I don't know if we would go so far as to say that all possible future exercises of market power have now been prevented. Our view -- and people will correct me if this is not our view -- is that what we saw in the first quarter of 2001 those particular problems were the result of these market design problems and those market design problems were addressed. So that particular way of exercising market power has now been taken care of.

Whether other ways of exercising market power could arise, we're not saying anything at this point as to that. But in terms of prices, the prices have been low since July since the second market fix went into effect, so at this point we are not inclined to take further steps.

COMMISSIONER MASSEY: Can someone articulate how the market rules allowed market power to be exercised, number one; and number two, how the market rules have been corrected so that that kind of exercise of market power is unlikely?

MS. WALDBAUER: The two things that happened that led to what happened in the first quarter of 2001 were this. First PJM had a regime where all of the deficiency charge revenues were allocated to capacity holders who were long. This created a scenario by which capacity holders essentially had no incentive to sell or provide capacity to the markets at lower prices because they knew they would either get high prices up to the deficiency charge, or that they would receive the deficiency charge revenues. PJM changed this and changed the allocation so that now both long capacity holders and compliant LSCs should share those revenues. That was the first market fix.

The second market fix, prior to the second change, capacity holders could list their generation capacity as ICAP as reserve capacity in PJM, and could de-list, basically on a day-by-day basis on days when capacity holders wanted to sell to PJM or provide reserve capacity to PJM, they could do that. On days when they wanted to sell outside PJM, they could do that too. That created a lot of volatility, a lot of uncertainty.

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PJM imposed a seasonal regime where now capacity holders have to commit for an entire season to reserve capacity members of PJM. So they must provide -- well, they don't have to, but they basically won't share any deficiency charge revenues if they don't. So they choose to provide reserve capacity for an entire season.

And the other side of that is that LSCs also basically are charged now, charged deficiency charges on a seasonal rather than a daily basis, so there is more incentive for LSCs to make long-term contractual arrangements and ensure that they will be in a good position in terms of meeting their reserve requirements.

COMMISSIONER MASSEY: Thank you. Well, let me say that I support this order, even though we are rejecting this complaint, I think the fact that it was brought to our attention has been very valuable to me in understanding capacity markets, how market power can be exercised in those regimes and how the likelihood that market power can be exercised can be eliminated, or not totally eliminated, but it could decline substantially with good market rules. And so I'm glad this was brought to our attention. It's really been food for thought even though we deny the complaint.

There's one other point, and that is I think as I recall the order says to the market monitor, we want you to bring these matters to our attention sooner.

MS. WALDBAUER: That's correct.

COMMISSIONER MASSEY: And I think that is an excellent addition to this order. If this had been brought to our attention -- anytime there's market power exercised and it can be brought to our attention quickly, it's much more likely that we can deal with it and come up with a timely remedy.

CHAIRMAN WOOD: I think as the language of the order points out, we recognize that here the MMU acted in a timely fashion by immediately upon observing an anomaly in the capacity markets in January 2001 apprised PJM's reliability of the problem and recommending tariff changes. If the MMU similarly notifies the Commission of such problems, we may be able to work with it and other affected entities to resolve problems even sooner than that.

So I would hope that we would probably in pretty short dispatch make that part of all the MMUs and not just PJMs. But we'll deal with that in a different proceeding. Thank you for pointing out that important aspect.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BREATHITT: Aye.

CHAIRMAN WOOD: Aye.

SECRETARY SALAS: The next item on the agenda is G-30, Standards for Business Practices of Interstate Natural

Gas Pipelines. And presenters for these items are Michael

Goldenberg and Kay Morice.

MR. GOLDENBERG: Well, now we're in the afternoon, so. G-30 is a final rule that amends the Commission's regulations to enhance the ability of releasing shippers to recall capacity. The rule allows releasing shippers to make full use of the four scheduling opportunities that pipelines are required to provide. The rule is also consistent with the overall goal of providing shippers with the opportunities to reschedule gas flows to meet their market needs.

The rule is going to be implemented in two phases. By May 1, 2002, pipelines must make tariff filings to be effective by July 1, 2002 that will allow shippers to recall capacity at the evening nomination cycle and to recall capacity that has not been scheduled by the replacement shippers for use on that day.

Second, the rule provides the North American Energy Standards Board with six months in which to develop standards for flowing day or partial day recalls. Comments on these standards are to be filed October 1, 2002 with reply comments by October 15th, 2002. Thank you.

COMMISSIONER MASSEY: I had a couple of questions about this. We have some parties in this case that -- in this rulemaking that believe that this change will actually undercut reliability and will damage liquidity in the secondary market. Has Staff taken a close look at those claims? And what is your view about those arguments?

MR. GOLDENBERG: The rule does examine those claims, and the rule finds that when a releasing shipper would include a partial day recall requirement in their release offer that the replacement shipper knows that what it's getting in that event is akin to interruptible service, and the replacement shipper under the rule will be given the same protection that the Commission has accorded to interruptible shippers who may be bumped by firm nominations. So the rule will provide that no replacement shipper can be bumped unless they have an opportunity to renominate that gas.

This was an issue the Commission originally looked at in Order Number 587-G with respect to whether or not we should allow inter-day nominations of firm service to bump interruptible service. The Commission concluded in that order that in order to give firm shippers all the rights that they are entitled to under their capacity, they needed to be given the right to bump interruptible shippers. And in order to maintain some reliability in the system, we wanted to make sure that the interruptible shippers would be given the opportunity to renominate any capacity if that capacity was bumped. So this rule provides the same protection to the replacement shippers.

COMMISSIONER MASSEY: Okay. One fear -- I think it's NYSOURCE expresses the fear that a domino effect might be created in which recalling capacity away from one market leaves another market scrambling to meet its customers needs. What about this concern? Is this a legitimate concern?

MR. GOLDENBERG: I think that the replacement shippers, as the rule points out, have the opportunity to protect themselves. If they don't want to enter into a release that has a partial day recall requirement in it, they don't have to. They can, for example, pay more money to get a release that doesn't have this condition in it. So the object of the rule is to make more releases available, because a lot of the LDC comments in particular pointed out that LDCs are today reluctant to release capacity at all because if they can't recall that capacity when they are the supplier of last resort -- excuse me. If the LDCs cannot get the capacity back when they release it, they won't release it at all.

Because under many of the state unbundling initiatives, the LDCs are the suppliers of last resort. And as a result, if, for example, one of their marketers fails to provide gas on a particular day, they need to get their capacity back in order to fulfill their supplier of last resort obligation. And so the object of the rule is to make more capacity available for release.

For replacement shippers who want more certainty, there's no requirement in the rule that there must be a partial day recall requirement. The releasing shippers, as it has since Order Number 636, has the ability to structure the release any way it wants. So if it wants to say there will be no partial day recall and the replacement shipper is wiling to pay for that right, they are able to do that.

And so in this way the rule creates sort of a fair market between the releasing shipper and the replacement shipper, where the releasing shipper can place whatever conditions it wants on the release, and the replacement shipper can evaluate those conditions and determine whether it wants to buy the capacity and what price it wants to pay for it.

COMMISSIONER MASSEY: So your view would be that this new policy would actually increase the liquidity in the secondary market while affording a fair measure of protection to shippers?

MR. GOLDENBERG: Yes, that's correct.

COMMISSIONER MASSEY: I'm for that. I wanted to express these concerns for the record because they were raised rather forcefully by some parties. But Staff has answered these questions very well and on balance, I favor this rule.

COMMISSIONER BREATHITT: Is that your vote?

COMMISSIONER MASSEY: And my vote is aye.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

SECRETARY SALAS: The next item is in the administrative agenda A-1, Agency Administrative Matters, and is a report on the Commission's current reporting requirements and future information needs. Presenting this morning for A-1 is Darrell Blakeway and Julia Lake, with Virginia Strasser and George Godding.

CHAIRMAN WOOD: While they're walking up, I wanted to put in context here, back in September these fine folks and others began to really catalog from a piece of -- a clean slate what it is that Staff thinks we need in the future world to really have good market information so that we can oversee the markets, provide some comfort to customers that the markets are working well, and also to provide transparency for participants in those markets. And that was a pretty formidable task that I know that at least three prior chairmen have attempted to do.

And to make sure that we move forward on this effort, I want today to put a stake in the sand with you folks presenting what we're up to and kind of lay out for us and for the public where we're going on market transparency and a better grip on market oversight. So with that broad intro, I'll let y'all take it away.

MR. BLAKEWAY: Mr. Chairman and Members of the Commission, I'm Darrell Blakeway. You've stolen most of my introduction already so I'll have to go from there.

(Laughter.)

MR. BLAKEWAY: To do this job, we were divided into two teams. My team was working on the future information needs and then Julie Lake's team was doing a complete inventory of all of the Commission's current reporting requirements, filing requirements, et cetera.

We do have a PowerPoint presentation to go with this, and starting with the first slide.

(Slide.)

MR. BLAKEWAY: I think this project -- the Staff has known this project needed to be done at least since FERC First. People realized that we needed to figure out new information sources in order to be able to engage in effective market monitoring. But what's occurred in the last couple of years in California probably gave this a major impetus as well as the support from you and your assistants. We realize we need to get on top of this situation of the market changes before they get out of hand.

We considered the issue of looking at what the Commission needs to know, what sort of information it had to access as fundamental to the Commission being able to do its job.

(Slide.)

MR. BLAKEWAY: So Slide 2 is just a quick overview of what we've done so far and what we're calling Phase I. Another team actually worked up, has reviewed FERC Form 1, which is the annual reports for major electric utilities, and they've made a number of recommendations to OMB that will have the effect of reducing the burden of that form and making it more efficient and rational and so forth.

And typically, that's the way the review of Commission reporting requirements has been done in the past, just a form every three years. What we were doing is trying to look at the big picture and at one time look at all of the requirements for both the gas and the electric industries.

(Slide.)

MR. BLAKEWAY: Going to Slide 3 says what we think needs to happen next which we're calling Phase II. We have to look beyond sort of our initial draft to decide what information is essential to meet the Commission's needs for monitoring and regulating. And we need to streamline the existing reporting requirements to make them more pertinent and more focused and concise.

We also have to think about what information we can get through third parties, because a lot of the information we need is not necessary to be filed -- it doesn't have to be filed with us. In many cases it shouldn't be filed with us because we really don't have the capacity to absorb it.

And then finally, having gone through that process, we would initiate a rulemaking. Then Slide 4.

(Slide.)

MR. BLAKEWAY: Julia's team, as I said, has looked all of the Commission's current reporting requirements for electric, natural gas and oil pipelines that are subject to our jurisdiction. And we don't think that's ever been done before in anybody's memory.

Slide 5.

(Slide.)

MR. BLAKEWAY: Her team found 43 reporting requirements and forms that relate specifically to the electric natural gas pipeline and oil pipeline industries and three that were generic reporting requirements that apply across the board.

Slide 6.

(Slide.)

MR. BLAKEWAY: My team attempted to look at all of the potential information the Commission may need to carry out its statutory obligations in today's market, today's changed and changing market. And as I said, from this we want to pare down to what we think is essential and also reconsider our draft report in terms of the specific regulatory policies that you're currently working on now, specifically the standard market design and other initiatives. Because in a sense, we can't know specifically what information the Commission needs until the Commission determines what policies it wants to utilize.

Next we need to engage, we think we need to engage the energy industry an the market participants, state commissions, other agencies, consumer advocates and so forth in identifying what information is most essential to enable the Commission to bring confidence in the stability and the fairness of the energy markets.

Slide 7.

(Slide.)

MR. BLAKEWAY: We started this project by looking at the Commission's strategic plan, the element to foster nationwide competitive energy markets and to protect customers and market participants through this oversight of the changing energy markets.

I don't want to overstate what we've accomplished at this point because we've just taken the first steps. They are necessary steps. But the most difficult part is still ahead, and that's to engage the industry and the market participants in a dialogue on this issue and determine how the Commission's energy needs can be met without unduly burdening reporting entities.

Slide 8.

(Slide.)

MR. BLAKEWAY: Now this slide presents both on the gas and the electric side so that the major topics or the major categories of information needs. Look at the top two items. Absolutely everyone we talked to agreed that the Commission needs to have timely and accurate information about the state of supply and demand because of the effects they have on prices in a competitive market.

And just to take you a little further down into the detail of our draft report, although it's not shown on the slide, if you look under the heading Regional and National Demand for Electricity, we've listed several items which are quite different form what we've listed for the demand for gas. So under electricity, for example, we need to know peak demand for summer, winter, annual and record peaks. We need to know demand for power-related ancillary services. We need to know information about load pocket demand, including ISOs and RTO loads, zonal loads, and some even bus-specific loads. We also need information about interruptible demand and the load management programs.

Then on the gas side under the same heading of demand information, we need to know the actual and relative use of pipelines and storage fields on a daily and annual basis. We need to know customer demand for transportation and storage services. We need to know prices for gas, including spot and forward prices as well as pipeline transportation rates.

Now just to take you down one level deeper into our draft, it you were to look at what we call the electricity data catalog at page 6 under the heading Peak Demand: Summer, Winter, Annual and Record Peaks, we have five data elements. The last one being NERC, RTO regions, coincident peak demand, stated in megawatts, combining the individual demands of control areas. And the catalog notes that possible sources of that information are the NERC and RTO annual reliability assessments and EIA Form 411. So that's the level of specificity that we've gotten to at this point.

Let's go to Slide 9, which we're calling Policy Challenges.

(Slide.)

MR. BLAKEWAY: These are some of the issues that we think will come up. We want to continue to explore possibilities of accessing information through public Web sites, as we do now to a very large extent, and reports of organizations that already collect energy data, such as

ISOs, state commissions, commercial energy information sources, reliability councils, trade associations. But the ISOs, for example, the ISO monitors have suggested to us that we may need to authorize their ability to access information that they need. It may need to be supported by Commission regulation and be subject to our own compliance mechanisms. So that would be an issue.

We think that those that manage the transportation and the transmission infrastructure will need to maintain the data on those transactions for some period of time in a format that can be quickly and easily accessed so that the Commission can get to that information as it needs to investigate anomalies. We wouldn't want to be receive information on billions of transactions, but we would like for it to be available in some standard format.

Now we get into this issue of what information is to remain confidential in order to protect the reporting enemies -- entities --

(Laughter.)

MR. BLAKEWAY: Reporting entities from competitive harm.

(Laughter.)

CHAIRMAN WOOD: Feed the man some lunch.

(Laughter.)

MR. BLAKEWAY: So there's the issue of

confidentiality. But then there's also the information on what should be available to all market participants and the public in order to provide for efficiency and fairness in the transparent market.

So then another policy concern, you have to weigh the burden. You have to weigh the public interest in having access to information against the costs of the burden. And these issues may be contentious and difficult.

(Slide.)

MR. BLAKEWAY: And Slide 10 is sort of where do we go from here. We think we need to coordinate our own revisions to reporting requirements with other agencies that are currently looking at their regulatory policies. We have had contact already with an EIA team that's reviewing its gas filing requirements, but I think we also need to talk to the SEC, the Commodities Futures Trading Commission, the FTC, and the Department of Justice so that we're --

The part that Julie has worked on, we want to take the information we have now and develop it into a searchable database so that it will be easy to find all reporting requirements on a particular topic and make it easy to compare and so forth. And then we want to begin a dialogue with the affected market participants, including state commissioners and the consumer representatives.

And I would think the model is the model you used for the standard market design to have workshops, outreach programs, possibly put -- when we have this draft perfected a little bit, put it on a Web site for comment. I think you can go to the industry and tell them you know what the problems in the energy markets have been and you know the Commission has to take effective steps to prevent a recurrence of these problems. So please tell us what information we should have to enable us to ensure confidence in the stability and the fairness of those markets. Given the recent crisis in the energy markets, all of the market participants should welcome these discussions.

Questions or comments?

CHAIRMAN WOOD: As do I welcome them. I appreciate y'all's diligence in preparing the data catalog and reviewing what we've got today so we don't -- there is probably going to be things that we no longer need to collect, that we need to just kind of send up the river, but the other things that we do need, and I appreciate y'all's sensitivity toward the fact that other agencies may already be getting this or other agencies may want to work with that and strongly encourage that effort. But just want to say certainly from my perspective, this is the first tier project at our Commission, and I appreciate such a stellar team on it. Look forward to finishing up page 10.

COMMISSIONER BROWNELL: I'd like to give them all the resources they need to get this done quickly, because I think the last point you made in terms of the importance of rebuilding confidence of all the participants in the market is in everybody's best interest.

I would like to simply make two points. I think it's great and important to be conferring with the other agencies to see who's collecting what. I'd also like to see us perhaps work towards some consensus among the agencies about collecting information in a format that allows all of us to use it, slice and dice it the way we need to use it but also recognizes the reporting burden on the companies.

I think we have lots of different agencies at different levels, and we certainly found this in the state, asking for the same information in different ways with a lot of costs and without much benefit.

The other thing I'd like to see us do is build in some review process. I don't want to call it sunset, but some discipline. Too often we collect data that, as you've discovered, we no longer need, is no longer relevant. And rather than find ourselves with this overwhelming task five years from now in a dynamic market we probably ought to be reviewing, I don't know, every six months or a year to see what information we're using, how we're using it, or indeed if we're not using it so we can build in the discipline up front. But bravo.

COMMISSIONER MASSEY: I think this is a very important effort. It sounds to me like you're on the right track. I'm very glad that we're doing this. It's been my impression since I've been at the Commission for almost nine years that there's a lot of information that perhaps we get that we don't need now or particularly want. There's information we don't get that need and we ought to be getting it. And there's information that ought to be made generally available to the marketplace that is not now.

So it seems to me that one of the last vestiges of market power in the industry might be control over information that really ought to be public in some form. I realize there are commercial sensitivity concerns as well. But my own view is that there ought to be a lot more information and data in the marketplace to allow the self-policing that we all want to see.

And so I think this is a very valuable effort. I commend you and look forward to working with you in finalizing this.

COMMISSIONER BREATHITT: I have a question on page 5 where you, in the third bullet, where you identified 43 reporting requirements and three that were generic to three program areas. I have no idea if 43 is considered a lot or a little bit. If I ask you, I guess your answer would be subjective, but --

MS. LAKE: When you're going through the reports, it was a lot. I'm not sure where you're going with the question. What do you -- there are a lot of reports there.

COMMISSIONER BREATHITT: I guess in the cataloging, you said this was the first time that this cataloging had been done to your knowledge.

MS. LAKE: Yes, ma'am.

COMMISSIONER BREATHITT: And it was more a question of curiosity if 43 was considered a huge, voluminous amount of data that we collect. I guess the next question is, do we use all of that in the 43 reporting requirements and that's what this exercise is going to determine?

MS. LAKE: Yes. It is what this exercise is going to determine. Some of these forms have been around for a very long time and some of them we've inherited from the ICC when we inherited jurisdiction over the oil pipelines. And while OMB requirements require us to review these things every three years, that's done on a pro forma kind of basis, and we generally don't get a lot of complaints about them so they just stay there until someone says I think we need to change them or need to update them. We tend to expand them rather than get rid of any forms. So we need to take a comprehensive look at it and see if this information is really used by the various program offices.

COMMISSIONER BREATHITT: I recall the three-year review that occurs with the Form 1 and the Form 2. Which is the electric, the 1, Form 1?

MR. GODDING: Form one.

COMMISSIONER BREATHITT: That parties, I think EEI was one of the parties that asked OMB to -- I don't know if they asked OMB to ask us to review that Form 1. I think it was a couple of years ago or maybe three years ago. I don't know if we ever did anything at that time with the Form 1. But when was the last time we changed the Form 1?

MR. GODDING: In fact, we just went through a Form 1 review. And on January 17th, we sent it to OMB, cutting out 11 schedules, which is about only 5, 7 percent of what's in that form. But it's a start. And I think the point here is we keep doing those things one at a time and we look at each form in isolation, and this effort and the cataloging effort as well as going forward is to try to take a global view of what we really need.

I think in answer to your first question, too, I think if you asked the industry they'd say it's a lot. We probably have a somewhat different perspective than they do.

COMMISSIONER BREATHITT: The number 43 is a small number, but what comprises each one could be from here up to the ceiling several times.

MR. GODDING: Sure. Well, I think, too, I mean, Form 1 can be very large, but also some of the forms, especially when you're talking about generics, that's -- a complaint is considered a form. So some of these things, you know, when you make a rate filing, that's also one of the 43 filings. So some of these are not, you know, every year you have to -- or we even have some that are monthly. But a lot of these forms are not of that nature. So you've got to balance what these forms are.

But there is a lot of data there, and there is data there I think we probably don't make good use of. A lot of the data we collect also not necessarily for our own review but to put it out there and to let the public review it, and we're required to do that.

COMMISSIONER BREATHITT: Will the team stay together? This exercise isn't over?

MR. GODDING: It's not over. But I don't know if we know whether we're staying together or not yet.

COMMISSIONER BREATHITT: Okay.

MR. GODDING: Probably other people will come in.

COMMISSIONER BREATHITT: Pat, you put these teams together when you came.

CHAIRMAN WOOD: I would love to take the credit, but I think I'm going to give it to some of our senior staff who saw the need that we'd all been talking about but got together the A Team here to do something about it.

COMMISSIONER BREATHITT: Good.

CHAIRMAN WOOD: It's just something we need to do.

MR. LARCAMP: Is there money for a condominium for these people?

(Laughter.)

COMMISSIONER BROWNELL: Thanks. If you're willing to write the check there is.

CHAIRMAN WOOD: All right. Y'all can wear shorts in the middle of winter. It's okay.

(Laughter.)

CHAIRMAN WOOD: Thank you all. I look forward to an ongoing update and whatever y'all need from us. Certainly the confidentiality issue is a big one, and you know, there is a middle ground there. There's a role that we or someone else can play in aggregating information that if it were granular would probably venture into commercial sensitivity issues but in the aggregate can be very good information for the market, much as AGA does for its storage report. They provide a value added function by aggregating that data, but the aggregate number is something that's pretty useful.

Bravo. Thank you. And we don't have a 2. So anything else, Madam Secretary? Meeting adjourned.

(Whereupon, at 12:45 p.m. on Wednesday, February

27, 2001, the meeting was adjourned.)