BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

\- - - - - - - - - - - - - - - - - x

IN THE MATTER OF: : Docket No.

TO STUDY THE ISSUE OF SECURITY : AD05-13-000

CONSTRAINED ECONOMIC DISPATCH :

\- - - - - - - - - - - - - - - - - x

Renaissance Esmeralda Resort and Spa

44-400 Indian Wells Lane

Indian Wells, CA 92210

Sunday, November 13, 2005

The above-entitled matter came on for conference, pursuant to notice at 1:05 p.m.

MODERATOR: SUEDEEN KELLY, FERC

COMMISSIONER

P R O C E E D I N G S

COMMISSIONER KELLY: -- And then we're going to have our panel. We have a number of panelists with us today who are going to give us their summary of how economic dispatch is performed in their areas and possible improvements to dispatch practices and the costs and benefits of additional economic dispatch practices.

After that we're going to take a break. And then the members of the Board are going to discuss what we heard today, see if we can come to a consensus on how -- what kinds of things we want to handle in the report, and we'll have an open mic at that time for people from the audience who might want to make comments or ask questions.

And I want to emphasize that we are beginning to compile a record here today. And the Panelists that are speaking will -- their remarks will be transcribed and will be in the record. But the record will be open so that any interested person who wants to add to the record may do so. And in fact, we encourage people to do that so that we can get a representative understanding of what's going on with economic dispatch in the west.

And with that, Marsha, I'm going to pass the microphone to you, if you have anything you want to add.

COMMISSIONER SMITH: Just a couple of comments. I guess I'm pleased to be here to work on this topic. And

I'm here, as much as anything, to learn whether there is something that my state public utility Commission should be doing about this because I don't see it as an item that we actively regulate or oversee but more as an item of real-time operation that happens in a control room.

So I think that's one thing I'm interested in, coming from a background where above all reliability is the most important thing to the customers in the first instance, in my experience, and cost comes second.

COMMISSIONER KELLY: Thanks, Marsha.

And then we'll start with a presentation by Bill Meroney.

Bill? Thanks. Are you going to speak from there?

MR. MERONEY: It's my understanding that I'm speaking from here.

I think they had a very active group here before and we didn't have enough time to re-arrange the room.

COMMISSIONER KELLY: Yeah. Can you speak louder, or is your mic on?

MR. MERONEY: Is this on?

(Simultaneous discussion.)

MR. MERONEY: I think it's also talking right into it.

Is this better?

COMMISSIONER KELLY: Maybe you need to move it closer.

MR. MERONEY: Okay.

How about this?

COMMISSIONER KELLY: That's good.

MR. MERONEY: Okay. Good. All right. Well, we'll rewind it and start again, then.

I'm Bill Meroney. I am with the FERC Office of Market Oversight and Investigations. But my reason for being here today is I'm part of the Staff team working on this topic. And I'd like to start by thanking the Board for the opportunity to present Staff's thoughts here on the subject of economic dispatch.

The general purpose of what I'm doing is to try to help the Board frame the topic of economic dispatch and sort of begin the discussion of what kinds of issues should end up in the report that the Board does. It really is a high level attempt at an overview of what appears to us to be some common elements in the way dispatch is approached economically by those who do dispatch.

We're fully aware of the large diversity of the way power systems are dispatched across different regions and within regions. But we have been given the responsibility in Congress to ultimately compile the recommendations that comes from the different regions. And so part of what we're trying to do is see to what extent there are some underlying themes that the joint boards can address.

My presentation today is certainly open to questions, as Commissioner Kelly said. But the transcriber has asked that when you ask a question make sure you state your name and affiliation. I'm sure the transcriber would be happy to hear your name and affiliation each time you ask a question. But my understanding is that the most important thing is to do it at least once the first time through.

So with that, the general overview that I'm going to give really has first just starting with the definition that we're taking as kind of a working starting point for economic dispatch. And then to talk about two parts or two components that we see in almost all dispatches throughout the country, and that's some form of planning for the dispatch the day before the power system is actually dispatched to meet load, and then a series of things that power systems always do or nearly always do to make sure that load is -- the load and supply are balanced during the day.

And then finally I'll address some of the factors that seem to be the kind of factors that affect how you can achieve lowest cost to customers within the framework of reliable operation of the system, and then talk about a few of the issues that we think are a reasonable set of starting points for what might be in the report.

So starting with a definition of economic dispatch. The definition that is in the EPAC is as follows: The operation or generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.

The sense that we get from talking to people and from our own experience is that at a certain high level this is not a bad definition but it really is fairly broad, and that there is a sense in which most, or certainly many electric power systems in the country dispatch their own generation units and other units that they may have under the control of their dispatch under some form of contract in a way that certainly they could say it meets this definition. Once you get a little more specific, I think you see lots of diversity in what people regard as economic dispatch. And I'll get into that a little bit as we go through the presentation.

But, as I said before, there are two main parts to -- that lead very directly into dispatching the power system to serve load. And while overall planning for the system certain starts long before the day before dispatch, the day before dispatch is typically the time when a utility or another entity that is responsible for the dispatch the next day needs to put in place some processes and some procedures so it knows what units -- what generation units will be available the next day to serve load.

By the way, one of the things we sort of struggled with a little bit when we were putting this presentation together was exactly at what level to do the presentation. We tried very hard to avoid having a presentation that was loaded with jargon, either technical jargon or FERC jargon. And it's possible even that we went the wrong way and that everybody in this room is thoroughly familiar with these concepts. And if that's the case, you know, if you all go to sleep I'll know that and I'll move through all these things really quickly. But really, very much, if you have questions coming through here either tap on your mic or say something or let me know and I'll be happy to entertain them and I'll deal with them as best I can.

But in scheduling for the next day the common practice is -- and I always hesitate when I say that because no practices are universal -- is to base the plans for the next day's dispatch on some forecast of load for the area where you're going to do the dispatch, and based on that forecast, to then select what generating units will be up and running and available for dispatch on the day. And the way that ends up being done the power system certainly has to recognize, looking at the generation fleet that you have out there and the other sources of power that you're going to actually be dispatching, what are the limits of what it is you're trying to dispatch.

And the kinds of things or the things that are sort of standard needs, things you have to recognize about the limitations of the facilities that you're going to dispatch, one of them is clearly how quickly a generator that's in place can move up and down when you need to change its output. It's obviously I think to most everybody that every generator can only be run at a certain level, so it has a maximum, but it's also the case that generators once they're running can't run below a certain level; that there is a minimum amount of time that a generator can be run; that there is a minimum amount of time that, once you turn it off you have to leave it off for a certain amount of time before you can have it on again.

All these things are very mundane in an engineering sense but it can be surprisingly complex in terms of the programming and the software that's needed even in a fairly simple context to perform these requirements sometimes called the unit commitment. And so utilities have heavily invested in computer software long before the Internet. But in today's world the software has become very sophisticated to do these things.

Well, the recognizing the limitations of the physical system is the thing that is in a way the security matter in the first instance. But not far behind that when you're looking at what generation to run is the question of cost. And the question of cost here then is a matter of recognizing what are the cost factors and the cost characteristics of the units that you're running. The most obvious one depends on what's the cost to generate the power, and that's typically dependent on two:

One, the efficiency, sometimes called the heat rate which says how much input do you have to put into a unit to get a certain amount of electric output, and so the obvious question then is how much does the input cost, and that's always the big driver: how much is the coal, how much is the gas and those kinds of things.

And then there are any number of other things that enter into the decision in the particular units: How much does it cost to start up particular units, for example. And it's also worth mentioning here that there are many other cost factors that computer programs may not take into account that one needs to worry about, one of the larger ones clearly being that there are other considerations. If you're looking at a system such a systems in the west, where there's a lot of hydro power, there are other uses for the underlying resource in this case -- water -- and there are a lot of other factors that need to go into the decision of exactly which units will be there tomorrow.

This is a function that's typically performed in a utility at least by a generation group because it's focused on generation.

Well, this is sort of the first part of the process leading to dispatch. And what we end up with out of this is, for tomorrow, an hourly schedule of generation, sometimes called a merit order that says I'm dispatching the units in the order of their cost.

Well, the next question -- that's part of the definition. The definition talked about the limitations of the generation system. That part of the process recognizes the generation system. And what we've called reliability assessment then goes and asks whether what it is that you plan for your generation system is actually going to be able to be delivered in the rest of your power system within the limits of the transmission facility.

So that's where, again, sophisticated computer programs come in and look at the flow of power throughout the system and do a test to see if the plans can actually be delivered. And that point it may be typically the case in most utilities that people have made their plans successfully. But there is a possibility of cycling back at that point if the plans turn out to be completely infeasible.

Once the power system is planned day ahead this way, if not much happens -- if everything tomorrow that was expected occurs then in a way what you've tried to do is plan for each hour the next day and each hour tried to get to the lowest cost. And if that's what you've done and if the world look exactly that way tomorrow then this process is probably very much the one that you'll see when you actually go to dispatch the system.

But of course, nothing ever works exactly that way. And even if it did you'd have to do at least two things during the day: One, you'd have to very carefully monitor load and generation and the interchange -- which is the imports and exports with your neighbors -- to make sure that load an supply were balanced. And clearly that -- one of the things you need to do is meet the NERC standards and produce electricity at 60 hertz throughout the day. And the other thing you need to do is look a little bit ahead in the hourly schedules to make sure that when you look forward the system will maintain balance.

The other thing that you're looking at is making sure that the transmission system remains within its reliability limits -- basically that so long as you don't have congestion the next day then the system will operate pretty much as planned and likely whatever you did for you dispatch is still going to be fairly close to what people would say would be economical lowest cost.

And this is where some other economic considerations come in because typically during the day, both in the western interconnection and the eastern interconnection, there's a series of procedures that people follow when congestion occurs, when lines get overloaded, a series of procedures to make sure that the system is brought back within balance. Typically these procedures are protocols to make sure that the system stays within those limits safely or if it goes beyond them slightly that it comes back very quickly within them. They typically do not take account of economics. They are simply procedures to make sure that the system continues to work reliably.

This function, whether it's -- in the utility context at least it's usually performed on the transmission side.

That's the sort of portion of my presentation that kind of deals with nuts and bolts of dispatch from day ahead through what's called in the technical context real time, which is when the load meets the supply.

The other part of the -- The remaining parts of my presentation focus on two things, really, certain factors that affect how effective the dispatch will be in minimizing customer costs and some issues that we see as starting points, as I said, for consideration by the Board.

The factors that we lay out really have kind of two sides: One is a 'what' side, what's included, what is part of the dispatch, and another side of 'how,' how is it really done, how is it implemented. So what we have sort of called area factors are really sometimes called scope factors that involve either the geography over which the dispatch occurs under the rough assumption that if the dispatch occurs over a larger area that the dispatch can occur over an area that's too small and if you enlarge the area of the dispatch you'd bring in more resources. And so when you went and looked through your available generation resources and tried to put them in order from the lowest cost to the highest cost you'd be including more when you did it rather than having two different areas doing that and then trying to coordinate back and forth between the areas.

Now at some point geographically -- this is a very complex world and a very complex system, and geographic areas conceivably could get too large. So there is at least a possibility on the other side that this area would be too large to be manageable. I don't think anybody has a good objective answer as to exactly what that should be. But it can be too small and it can be too large.

One of the other issues -- that is the issues that the DOE report I think -- or at least includes the issue that the DOE was charged with looking at is what generation resources are included, but in particular how generation resources of independent power are able to enter in the dispatch and what effect that that has on the economic dispatch.

Another kind of related issue could be -- could relate to the transmission facilities that are included if there is multiple transmission ownership within the area of the dispatch, for example. One of the other kind of considerations -- some are technical -- is if you are checking your reliability in your own area to what extent does the representation that you have of the transmission system actually bring in transmission outside your area and, if it does, how do you get that information and how do you -- if there are issues of loop flow from wider areas, how is that incorporated in the dispatch.

The other sort of set of factors that bears at least kind of consideration in this area is things we've called implementation factors: it's the 'how' part and the first one we listed is the 'when' part, which is how frequently you do a dispatch. This is maybe somewhat more of direct applicability in the context like an ISO that does dispatch below the hourly basis. Pretty much outside the ISOs I think we've worked largely on an hourly framework.

And while it's certainly conceivable to talk about making that for -- that dispatch interval a lot shorter in certain ways, this is probably a first -- I know this issue has come up, for example, in the California ISO and some of the redesign and things like that.

Another issue of general importance is communication of information back and forth between the party doing the dispatch and anyone else who is subject to the dispatch. So that the arrangements and coordination are in place if the -- between how you -- the transmission side of an entity dispatches the resources, both resources that come from the other side of that same entity and potentially resources outside from third parties or from outside its region.

Finally another issues is -- not finally -- one other issue certainly is software and what software is available, what benefits could come from upgrading software. And certainly software is not free. So the issue really becomes when and at what cost to bring in modifications in the software side of the exercise.

And last but by no means least I think there is the issue of how coordination takes place across regions. Right now one of the -- both in the east and in the west a certain amount of coordination within the day to bring a system that is congested or is not in the state that was planned the day before, many of those procedures don't take in the first instance into economics, although often, for example, the accommodation that can be required can be done economically on a local level by people doing that accommodation. There's certainly the question of how well this coordination works and could it be made to work better is one of the things that one could entertain as a topic of discussion.

The last set of things that I'd like to talk about briefly just are the issues. And there are nothing more than a sort of suggested things that we have thought of that I think you also have -- Board members may have seen either in an email and is kind of part of -- I believe it's Attachment B or one of the attachments with the agenda. And these are, if not identical questions, they are quite similar.

COMMISSIONER SMITH: Bill?

MR. MERONEY: Yes.

COMMISSIONER SMITH: Would you take a question?

MR. MERONEY: Absolutely.

COMMISSIONER SMITH: I was curious about your last comment on the coordination needed among regions.

MR. MERONEY: Yes.

COMMISSIONER SMITH: What do you mean by -- when you a 'a region' in the west?

MR. MERONEY: Okay. What I --

COMMISSIONER SMITH: Are you seeing the west as one big region or are you seeing the west as several regions?

MR. MERONEY: It might have been a little more accurate if what I said was coordination among the dispatches is what I'm seeing. What I'm talking about here is that a company would do a dispatch or a control area or a balancing to do a dispatch, and then if it needs to change its dispatch or if conditions changed during the day so that there might -- a load may shift in ways that there would be cheaper power outside that area, how is it brought into the area to reduce costs, on those kinds of issues, whereas if it happened in the area you could -- you would -- you would not need to coordinate with your neighbors. It may well be that coordination with neighbors works pretty well so that where neighboring control areas, utility areas actually do a pretty good job during the day.

But I think one of the issues just is whether and to what extent is a more regional orientation for the dispatch, are there areas of improvement that could come in there.

So the last list that I'll read fairly briefly is just potential topics and one is just in terms of what could go in the report, what's the current practice of economic dispatch in the region, and what's the scope of the dispatch, who does it, and those kinds of things. What improvements -- really it's appropriate probably here to say if any -- should be considered if -- and you know this is from everybody's perspective and I'm sure there will be different perspectives on what improvements -- and certainly on the if any as well.

And to the extent that people identify improvements you can -- you know, there may be improvements in principle but what are the practical benefits and costs of these improvements.

Then certainly any -- some improvements may be neutral with reliability. Some improvements, if you improve the economics, other things being equal, you ought to be improving the reliability at the same time. But life isn't always that simple. And so any significant change needs to be kind of assessed in terms of potential effect on reliability.

And certainly last, and again not least, is what are the impediments to any improvements that people might consider: institutional, regulatory, statutory and, you know, how would those be considered in actually applying any improvement.

So that's the end of my presentation. Hopefully I've been close enough to the mic that everybody's heard me in the last part.

COMMISSIONER KELLY: Thanks, Bill.

Does anyone have any questions for Bill?

Ric.

CHAIRMAN CAMPBELL: This is Ric Campbell from Utah.

Before I begin any assignment I always like to ask the question why. I believe we've got a very good nuts and bolts presentation here that you've presented to us. I guess my question is do you know the story behind why this is in the energy bill.

Is there some story about uneconomic dispatch that we need to be aware of as we talk about solutions to make sure we actually address whatever generated -- or whatever the genesis of this problem is.

MR. MERONEY: We'd love an answer to that question.

COMMISSIONER KELLY: Pardon?

MR. MERONEY: We don't have an answer to that question. I don't think -- you know, certainly Staff has not encountered anyone who has given us a very clear answer on what this is beyond what's stated there. But what's stated there is, you know, anyone who's read it, is it's fairly open ended.

COMMISSIONER KELLY: Well, Ric, my understanding is as the energy bill is being debated there were various proposals that were made in the course of deliberation about the drafting of the bill.

And one of the things that was considered was whether -- quote, unquote -- economic dispatch, some type of economic dispatch should be directed -- whether control areas should be directed to consider it, whether states should be directed to consider it, whether FERC should be directed to consider it. And needless to say, there was a lot of back and forth about whether economic dispatch or the principle of economic dispatch should be in the bill and if it was whose job it would be to look into economic dispatch. And once economic dispatch was looked into, what should be done with it.

So as I understand the way that issue was settled was to call for a report both for the Department of Energy and the Federal Energy Regulatory Commission to do research, study how economic dispatch is currently being conducted around the country, and do a study about what else could be done to enhance economic dispatch. And also look into the pros and cons of enhancing economic dispatch.

So I think this is Congress's -- this reflects Congress's interest in better understanding how economic dispatch in all of its various forms is undertaken around the country.

MR. MERONEY: And I think Staff has taken, you know, a fairly wide view like that consistent with our understanding. And we don't know specifics in answer to the why. But certainly one of the characteristics of this particular session was that it made reference not in the titles of the section but in the body of the section to security constrained economic dispatch, which is sometimes fairly narrowly drawn.

And I think we felt in reading this and looking at the DOE side that there was this more general concept of economic dispatch and that did apply to things that were common across the country in different ways. And that what we were really asked to do was to -- in our portion was to kind of go back to the regions and insofar as we can sort of, you know, inform them about what we knew, give them the opportunity to kind of ask this question in their own regions for their own regions about what, when they looked and studied their own dispatch in their own regions, just where were there areas of improvement that they could see that would enhance, say, just the economics, the cost to consumers and either improve reliability or keep it at least as high as it was originally.

So we took a very -- a fairly -- from a technical standpoint I think a fairly broad view of economic dispatch, although we did focus it on leading up to the actual dispatch of the power system in real time rather than broaden it beyond.

COMMISSIONER KELLY: Yes.

MR. HINKLEY: Richard Hinckley of Nevada. I believe this is a background kind of question.

In the decades prior to maybe the mid-90s when deregulation kind of took its many forms in various states it seemed to me that there was a vibrant economy purchased power market, utilities buying from each other on an economy basis for cost reasons and reliability reasons at times as well.

Is there any reason to think or know that today, given the characteristics of the wholesale market, that that vibrancy that the economy purchased power market is different than it was, if it's not being used as much, if there are constraints, or that there are different characteristics now for whatever reason?

COMMISSIONER KELLY: Well, I think that you ask a very good question. And I hope that some of our panelists will be able to shed light on that. Certainly they're going to talk about how it's done in each of their regions today. And I think to the extent they can talk about how it has changed over the last ten, twelve years, that would be helpful.

MR. MERONEY: I think that's a good example of why you come back to regions because I think if you look at the power markets back in the time you're referring you're looking at very different ways in which similar practices played out in the west and in the east. And today as well. So I mean I think it's a very appropriate question.

COMMISSIONER KELLY: Dian.

COMMISSIONER GRUENEICH: Yes. Dian Grueneich, Commissioner from California. I actually have two questions:

One is it seems to me it's significant that the federal act used the term security constrained economic dispatch and not just economic dispatch. And I think you just alluded to that you saw a difference between general economic dispatch and security constrained economic dispatch. And could you elucidate a bit of what you see as the difference and are we then looking at it through the lens of security constrained economic dispatch. That's my first question.

So if you could respond to that, that would be great.

MR. MERONEY: Well, I think we -- One thing that the Commission I believe -- in certainly one of the early orders here kind of adopted the definition that was in the section 1234 on the DOE study as what it was using as a definition. And one reason to at least think that that moves in the direction of security constrained economic dispatch is when some people think of pure economic dispatch as if you read that original definition and leave out transmission facilities. It's a dispatch of merit order of your whole generation system. And the security constrained issue comes in when you bring in the transmission.

And then there's a more specific definition that perhaps California and the ISO is considering, particularly in the MRTU and other ISOs use, that has to do with fully incorporating all the transmission constraints whenever you consider how to dispatch generation. And some people consider only the latter very detailed thing to be security constrained economic dispatch. I mean, just as a starter, I did -- and it becomes an acronym, SCED. You do SCED on Google you get all the ISO stuff and you get just a little bit of everybody else.

I think we felt that that was a bit narrow just to simply focus it on that. And that I think to an extent -- and again, as soon as you get below this definition and try to be more specific it's hard to get agreement -- is that there's a break point here between dispatching your generation in what would be classically be in merit order of the generation under your control and bringing in the transmission limits, which gets you into more of a security constrained dispatch. And then you argue whether you do them together, you do them separately, or so on.

But I think that we are comfortable -- pretty comfortable with taking this definition for purposes here as a working definition that that includes both economics and security constraints.

COMMISSIONER GRUENEICH: Now my second question was again looking at the definition that's taken from the act of economic dispatch as it refers to the lowest cost. And in terms of the work that I guess this Board will be doing, are we using lowest cost in view of lowest life-cycle cost, or is this an exploration that basically is going to say how are the various entities defining what lowest cost is.

So, to be a little clearer, are we taking as a given that there is some definition of lowest cost or are we going to be looking at, assuming there are entities dispatching using lowest cost, is there a difference in how they're defining lowest cost.

COMMISSIONER KELLY: Can I take a stab at that, Bill?

MR. MERONEY: Yes. I'd like you to, actually.

(Laughter.)

COMMISSIONER KELLY: Okay.

Well, I think Dian raises a very good question right of the bat because how you do your dispatch -- as I look at the tree of how you do your dispatch, one is cost based dispatch and the other is bid based dispatch. So in an organized market, for example, that the California Independent System operator has -- which is basically the only organized market that we have in the west as contrasted with New England PJM and MISO -- will look at how the ISO does it in a bid based dispatch with a single clearing price. And so that's fundamentally different and the order of dispatch is based on bid, which presumably relates to cost, incremental cost, but not necessarily exactly.

And then the other part of the universe is cost based economic dispatch.

And as I understand it, how people determine their cost can vary somewhat, but it has to do with the incremental energy cost of each of the units. And that incremental energy costs include startup cost of the unit, no load costs, and variable O&M costs, and then potentially includes incremental transmission losses. And after that it gets more -- it gets broader. Perhaps one would take into consideration lost opportunity costs for hydro storage systems and maybe cost of credit arrangements involved in dispatching a system.

But I think it's cost based or bid based. And within cost based it's incremental. It's the incremental cost of the unit.

Is that a fair statement, Bill?

MR. MERONEY: I couldn't do better.

COMMISSIONER KELLY: I'm glad that you work for me.

(Laughter.)

COMMISSIONER GRUENEICH: My last one will just be a comment that it seems to me in addition where there are states such as California that have a renewable portfolio standard and ours is based upon actual operation, it's not just having the contracts, and at some point this has got to take that into account, I think how that's folded in as to whether it's folded in under the bid, is it folded in under the cost analysis or is it folded in as just a separate discrete area.

COMMISSIONER KELLY: I think that you raise a very good point. And maybe that helps to give an overview of how dispatch occurs.

Presumably in any dispatch economics is taken into account, although we'll hear from Bonneville and it may be that when you have a system that's primarily hydro storage based -- a storage based hydro system, it may be that economics isn't taken into account at all. But Bonneville will tell us about it and the rest of our friends in the Northwest about how it works there.

But if you take thermal units, either bid based or cost based, you have an order. But that is, as you mentioned, only one aspect of the dispatch. The other part of the dispatch, the overriding concern is reliability. So how you dispatch within that merit order based on cost is going to be informed by the number one concern, to maintain reliability.

And then there may also be other concerns that are taken into account separately from cost. As you say, a renewable standard -- a renewable portfolio standard -- or other environmental costs. It could be air emissions.

So that in addition to the economic aspect of the dispatch are the other values that are met in dispatch. So I think as we hear from our panelists as we talk about what could be done to enhance economic dispatch we have to understand what the costs and benefits are of that. And it may be that sometimes one can't enhance economic dispatch without undercutting some of the other values. But it may be that there is room to enhance economic dispatch while still maintaining the other values.

COMMISSIONER KELLY: Shirley.

COMISSIONER BACA: I have a question.

If we're monitoring our hourly dispatches to ensure that the dispatch for the next hour will be in balance then how can we limit the new power flow schedules and curtail the existing power flow schedules if the dispatch schedules are based on meeting the need load and he reliability?

MR. MERONEY: Well, your -- Let me make sure -- I want to make sure I understand your question because I was simply saying you look ahead, not just at what's going on in this hour. You look ahead to the next hour. And you don't -- You may, depending on what you're seeing coming up the next hour, you may take one of a number of different actions if you need to because you see transmission facilities having a problem --

COMISSIONER BACA: Okay. Well, it just seemed to me that you presupposed that it's not being done by saying that you're going to curtail a future new power flow. It just seemed to me like it was --

MR. MERONEY: Well, if you have somebody -- if you have a schedule coming in the next hour. You have a reasonable picture of where things are going to be next hour. And as you're coming into the hour if there are -- you're in a situation very much like you would want to be in when you're in this hour, which is that you can see that certain flows would have certain effects. You need to act before those effects happen when they're imminent on the schedules --

COMISSIONER BACA: I understand that. It just presupposes that it's not being done. So are you saying that it currently is not being done?

MR. MERONEY: Oh, no. No. I mean that's what people do now. Is that what you mean?

In other words, I think people are doing that now. They need to. It's part of running the system; it's actually part of the protocol. So, I mean, no. The intent there was to describe what people actually do because they're doing it now.

COMMISSIONER KELLY: Tom. We'll take one more question. Go ahead.

COMISSIONER SCHNEIDER: I was just going to add one thing to the list of other considerations that you talked about. And that is for an intermittent renewable resource like wind you recognize that it is intermittent. You need to integrate it. It is an energy resource with some component of capacity. And it's equivalent or at least it needs to be looked at in terms of a must-run kind of thing. If it's there it is going to be flowing consistently.

COMMISSIONER KELLY: Thank you.

Thank you, Bill. I appreciate it. And you'll be with us for questions as we go along, right?

MR. MERONEY: I'm sticking around.

COMMISSIONER KELLY: Thanks.

And now I am pleased to introduce Kevin Kolevar.

Kevin, thank you very much for coming today. I know that the Department of Energy is working on its economic dispatch report. And we've jumped the gun a little bit on your release of your report by having this meeting before you have finalized it. And so I really appreciate your willingness to come and give us a preview of what you've found in your research.

MR. KOLEVAR: Commissioner, thank you for having me.

I had hoped to actually be able to say more about it than I am, and the reason is is because the report is still in inter-agency review. It has cleared the Department of Energy, and I expect it shortly. I expect it will be released this week and be made available on our website along with comments. And then, per the Chairman's direction in the southern board meeting, which is going on concurrently, it is my understanding that it will also be posted in the record of proceedings taking place today.

I can tell you that -- I think without giving away more on it than I should -- it does speak to the enormous complexity of the issue. And understanding that within 90 days we were not capable of turning around a product that met all of the requirements, the statutory requirements laid out in the language, the most notable exception being the recommendations.

It's clear -- It was clear in the run-up to this report being included in the language that Congress was interested in some very substantive recommendations as to the value of economic dispatch, as to what could be done to improve economic dispatch I think both from a generation side and from a regulating side. And the fact is that in 90 days that's just not something that can be turned around.

And so for that reason we had to treat it more as a compilation of practices across the country and note some of the discrepancies between those practices, and then speak generally to some areas where there might be room for improvement.

I will tell you, though, that it does draw a very clear distinction between economic dispatch and efficient dispatch. I think it speaks to that appropriately. And I will tell you, Commissioner, as well that it recognizes the boards that are taking place today and that are going to be taking place over the next several weeks. And I think it envisions a role for some of the information that's developed out of these to play --

VOICE: Put the mic --

COMISSIONER SCHNEIDER: I'm sorry.

And it does envision -- perhaps it's cautiously optimistic because we need to see how these board play out. But it does see value in the boards and a role in the information derived from these boards in, you know, continuing to wrestle with some of the tough issues that have been raised on economic dispatch.

COMMISSIONER KELLY: Thanks, Kevin.

Are there any questions for Kevin?

COMMISSIONER SMITH: Kevin, I was just interested by your use of the word 'discrepancies.' Does that mean there is some sense that there is a correct way and an incorrect way?

COMISSIONER SCHNEIDER: Not at the Department at this time.

I'm certain that in the states there are differences in the way they practice. But I will tell you that this is not something that we speak to in substance in this report.

COMMISSIONER SMITH: So perhaps you just meant there are different ways of doing it and people are doing it different ways.

COMISSIONER SCHNEIDER: That's right.

COMMISSIONER SMITH: Okay. Thanks.

COMMISSIONER KELLY: Any other questions?

(No response.)

COMMISSIONER KELLY: Thanks, Kevin. We appreciate it.

We have a number of panelists with us today. And what we wanted to accomplish through this section of the meeting was to give all of us an understanding of how economic dispatch is actually performed within a utility within the California Independent System Operator region and how it works, and give you an opportunity to ask questions to better understand how it works.

And then we also asked our panelists to speak to what improvements could be made to those dispatch practices and what the pros and cons of making improvements are.

So with that I'd like to turn the microphone over to our first panelist, Mark Rothleder. Mark is with the California Independent System Operator. And Mark is the principal market developer there.

Thanks, Mark, for being here. Appreciate it.

MR. ROTHLEDER: Thank you, Commissioner.

I think I have about five minutes.

COMMISSIONER KELLY: You have five minutes, yes.

MR. ROTHLEDER: Okay.

COMMISSIONER KELLY: But we can give you a few extra minutes if you need it.

MR. ROTHLEDER: Okay.

COMMISSIONER KELLY: Amazingly enough, we're running early.

MR. ROTHLEDER: Okay.

Let me give you kind of the evolution of dispatch within the California ISO. And you have to go back to 1998 when we transitioned from the dispatch practices of the three investor-owned utilities, PG&E, Southern California Edison and San Diego Gas & Electric, who were basically performing traditional economic dispatch, what I call system lambda economic dispatch, using their energy management system.

As you described that dispatch was traditionally to minimize the cost based on the heat rate of the fleet of thermal resources. In addition, for some of the investor-owned utilities who had large amounts of hydro generation, additional things would take place prior to real time, and some of those things would be to perform a hydro thermal optimization, which is not traditionally considered economic dispatch, but it is a function that tries to balance the economics and the water needs with the expected system energy needs.

So you had three control areas at that time. And then in 1998 when the California ISO started up we basically formed one control area, in which case the -- really integrated the economic dispatch or the dispatch of the resources for those three areas. Order of magnitude, those areas put together account for now over 45,000 megawatts of peak load.

Until October of 2004 our dispatch process was basically a merit order dispatch. And I distinguish a merit order dispatch from an economic dispatch in that the merit order dispatch, you kind of go up the merit order stack and the price is set by the highest resource dispatched. But it doesn't full recognize things like ramp rate constraints and trade offs that may occur in subsequent five-minute intervals when potentially a lower or ramp rate limited resource now has more energy available as a result of its next five minutes of energy being available. That didn't take place.

In October 2004 we moved to an economic dispatch routine which did do those tradeoffs. And that is performed every five minutes.

I'll get into a little more detail there. But just looking forward a little bit, this economic dispatch currently does recognize the transmission in the sense that we do enforce the large interzonal transmission constraints, that being things like Path 15, Path 26, for those people who understand the WECC grid.

In 2007 we are currently working on an upgrade, the market redesign and technology upgrade, also known as MRTU. This change will basically introduce now a day ahead dispatch process which will consider hourly dispatches for every hour as well as a real time -- both a day ahead and real time security constrained economic dispatch.

The reason I say security constrained now and I introduce that term is because, exactly as what we spoke about earlier, we're now considering all the constraints, the constraints of the network that we are controller/operator for. As a result of that it's not just a large path, Path 15 or Path 26 that are enforced, but other transmission constraints.

COMMISSIONER KELLY: Mark, can I ask you a question about that?

MR. ROTHLEDER: Yes.

COMMISSIONER KELLY: When you take those transmission constraints into account, does that direct how you stack them in merit order or do you do that after you have them stacked?

MR. ROTHLEDER: It really is co-optimized.

In other words, the transmission constraints, to the extent they are binding what would otherwise have been the economic dispatch, then the dispatch reflects the constraints. And basically it will redispatch resources to both minimize the cost as well as ensure that the constraints are not violated.

COMMISSIONER KELLY: Thank you.

MR. ROTHLEDER: Going back to how the economic dispatch -- and some of the things to consider in our current system. We do have a function that does look ahead.

We look as far as approximately two hours out. So although we're dispatching in real time for the next five-minute interval, we are looking and forecasting our imbalance energy needs based on our load forecasts for the next two hours out. But it's only the next five minutes that's a binding dispatch.

The reason this look-head feature is important is because you can start to see, as an analogy, turns in the road before you get there. And if you were just dispatch for the next five minutes it would be almost like driving with your headlights off at night and you're coming into a turn. Your actions that you would take once you got into the turn are much more abrupt than had you had your headlights on and looking forward.

And the turns in the road are quite applicable. When you look at the load curve and things that happen in the load curve, they literally are turns in the road.

The other thing to point out is although you have an hourly bilateral market and for us, when we see the bilateral schedules we ensure that they fit onto the transmission system, the hourly set of schedules does not reflect what the intra-hour changes of load are. There are significant things that happen within the hour that have to be accommodated within the real time dispatch.

One of them is the load is obviously changing within the hour. It doesn't just perform a stairstep change as you go through hour by hour. But in the west there is also -- at leas for the California ISO -- a significant thing that has to be accommodated are large hourly transactional changes. And these transactions can be contractual changes with resources within California; but these can also reflect in large amounts of changes of interchange with neighboring control areas.

During certain hours it is not unusual for us to have a change of 3- or potentially 4000 megawatts of hourly schedule change from one hour to the next on a net basis with neighboring control areas.

COMMISSIONER KELLY: When you say neighboring control areas you mean control areas adjacent to but outside of the ISO?

MR. ROTHLEDER: It's really all of them, whether it be internal -- I'm sorry, control areas that are embedded within or control areas that are neighboring and outside of the ISO.

The reason I point this out is the current practice in the west is that these schedule changes occur across the top of the hour, starting from ten minutes prior to the top of the hour and it goes to ten minutes after the top of the hour. And 4,000 megawatts changing over 20 minutes is quite a significant change and is much more significant than the change in load itself, and much faster than the change in load itself.

How this reflects in the dispatch and the prices is you oftentimes will see volatility in the prices because you will see at the beginning of the hour as load is rising you have too much energy because you have the hourly transactions coming in early and then as the load continues to rise at its rate through the hour the prices and the dispatches start to climb.

Our participants have complained about some of this because what they feel is this is causing both price and dispatch volatility. Now the concern about the dispatch volatility is that some of these resources, oftentimes thermal resources, have not traditionally been used to go up and down as often as they are now doing so. And some of the things that they feel that have to be considered are the effects of this up and down dispatch on maintenance costs and so forth.

COMMISSIONER KELLY: Is the software designed to take that into account?

MR. ROTHLEDER: It's not directly taken into account. Again, as you mentioned, we do have a bid based market. To the extent that that's a concern they have the ability to incorporate those types of things into their bid.

I want to contrast this with some of the practices of I believe the east, where they don't have one ramp of interchange during the hour; they actually schedule their ramps of interchange and spread them out over the hour and distribute them so that they're not so large in magnitude.

COMMISSIONER KELLY: And do you think one is preferable to the other?

MR. ROTHLEDER: At this point I believe it would be better to spread them out and decrease the magnitude of those changes. And I think the west should consider those types of practices, consider how we could do that in the west. But that is a coordination effort. One control area alone can't make that happen; this has to be done on a coordinated basis.

As far as the types of resources dispatched, going from the three OUUs where they were basically dispatching their thermal fleet, we now have the ability to, through the bid based approach, expand the set of resources that we can consider in the economic dispatch. And as a result of that, resources that traditionally have not had control signals sent to them directly through the AGC or EMS system now are able to participate in market.

So that includes hydro resources, some qualifying facilities who find they can participate in the market. But also demand response and other resources like this.

Demand response can directly participate but they can also participate by at least seeing the signals, the price signals that are presented as a result of the economic dispatch.

We do have intermittent resources in the form of wind and we have a special program for the intermittent resources in California that recognize that when they are producing we would take the energy. And they are, rather than being exposed to the price fluctuations every five minutes, they are able to net those fluctuations over basically a month. As a result they have more of an incentive to participate now in the market.

You did mention already we do have control areas -- We have control areas that are embedded within the ISO and more forming. But we also have what are called metered subsystems. And these are entities that are -- basically they kind of do their own dispatch oftentimes through an economic order but they're not participating necessarily -- although they can participate -- in the larger regional or the California ISO's economic dispatch. And it provides them at least the flexibility to, to the extent they want, to do their own economic dispatch with their sets of resources.

I think I've touched on the major points that I wanted to make. And I'll at this point pass it along.

COMMISSIONER KELLY: Thank you, Mark.

MR. ROTHLEDER: Or entertain any questions.

COMMISSIONER KELLY: Do we have a question for Mark?

Ric.

CHAIRMAN CAMPBELL: Rick Campbell from Utah.

It was unclear to me when you talked about spreading the hourly changes and how in the east they spread those out over the hour. How large a region -- Does that -- For us to do that in the west or an interconnect, does that have to be done over the entire interconnect or some subset of that?

It was unclear to me the geographic scope.

MR. ROTHLEDER: Basically the WECC, the whole region interchange transactions are basically changed through the process at the top of the hour, ten minutes prior to ten minutes after. That has to be done in a coordinated manner; otherwise you start to get unscheduled flows between control areas that you wouldn't want.

And so if any changes were to be made in terms of spreading that out, doing it more often during the hour with a smaller magnitude of changes, that would have to be done across the WECC.

COMMISSIONER KELLY: Thanks, Mark.

Our next speaker is Doug Larson. Doug is with

PacifiCorp where he is the Vice President in charge of Regulation.

Doug, thanks for coming today. And would you mind starting out your presentation with a description of where you are in the Northwest, what your territory -- your service areas are?

MR. LARSON: Absolutely. In fact, that's the first part of my remarks.

First I would like to start by thanking the Commission for providing PacifiCorp with the opportunity to present our perspective on the benefits, issues and obstacles associated with security constrained economic dispatch in the western region market.

And, as Commissioner Kelly said, for those of you that are unfamiliar with PacifiCorp, we provide electric service to approximately 1.6 million retail customers located in parts of California, Idaho, Oregon, Utah, Wyoming and Washington State.

As a vertically integrated utility our retail service is regulated by the utility Commission of the six states that we serve. These Commissions act to ensure that our retail customers receive reliable and reasonably priced electricity consistent with state integrated resource requirements.

Nationally PacifiCorp believes that given the diversity of utility structures across the geographic regions issues involving the dispatch of generation resources by utilities are more appropriately addressed by state regulators and not the federal government. But while a federally mandated change to state regulated dispatch procedures would be unwarranted, as we have made statements to the Department of Energy, PacifiCorp also believes it would be equally irresponsible on our part to ignore opportunities to improve current practices across our region.

To put our position in proper context I'd like to briefly explain our current dispatch procedure and how we view economic dispatch generally, including factors we believe must be considered when exploring the effectiveness of greater non-utility generator dispatch.

And then finally I'll close with some suggestions for improving economic dispatch in our region.

PacifiCorp currently economically dispatches its diverse system portfolio, both our own generation and generation that is under contract of coal fired, natural gas fired, hydro, wind and contracted resources at the lowest cost to our customers. It is subject to the constraints such as control area boundaries, transmission limitations, reliability concerns, fuel constraints and certain business procedures such as credit agreements and risk on physical delivery.

PacifiCorp's operational practices are consistent with the procedures required by federal and state tariffs and rules as well as our interpretation of the federal act. We believe it could be improved as I will describe in a minute.

PacifiCorp dispatches its generations in our two control areas utilizing a resource stack compiled and prioritized based on cost data and also the dispatchability of those resources. Once the stack is compiled resources under PacifiCorp's control are dispatched in merit order based on the costs that are available in that resource stack regardless of the ownership of those specific units.

Thus our decision process is premised on our generation dispatch function having all of the necessary access to price information for and real time control over those available resources.

PacifiCorp constantly reviews and, where appropriate, modifies opportunity cost determinations. For hydro generation in particular this is a complex area in determination based on pretty dynamic factors.

As the term economic dispatch is used in policy discussions PacifiCorp believes that economic dispatch must be understood to mean real time operation of generation facilities in order to produce energy at the lowest cost to serve customers, recognizing that any operational limits of generation and transmission facilities and other non-physical constraints, including credit concerns, environmental considerations, and fuel constraints such as competing uses of water and other operation of hydro facilities, should be considered.

Also it must be understood that the dispatch of all energy constrained generation, including hydro with discretionary storage capability, must be based on a determination of the opportunity cost. Otherwise these resources won't be used to their greatest extent and at times when those resources have maximum value.

COMMISSIONER KELLY: Doug, can I ask you a question about your opportunity cost considerations? Do you attempt to quantify those or is it a qualitative judgment?

MR. LARSON: Well, I think there is, based on forward price curves, I mean looking at what the cost of peak power is going to be at any, you know, given point in time, obviously in our system, I mean you would run the thermal units to the maximum extent possible. Those are obviously running at night. And we have special contracts with Bonneville for peaking resources that will be used in the day. So to the extent that you can under the limitations of stream flows and other environmental impact limitations, you're using the hydro at the highest cost times.

And it's -- I think it's, you know, it's somewhat quantitative and somewhat qualitative.

COMMISSIONER KELLY: Thanks.

MR. LARSON: This issue of hydro is obviously very strong and a big concern in the Pacific Northwest where a significant amount of our generation as well as generation that Bonneville Power Administration dispatches is hydro-based.

Economic dispatch considerations. As to the larger policy question of the implications for retail customers from greater dispatch and use of non-utility generation, PacifiCorp believes that numerous factors must be considered in that equation, including the location, the transmission limitations, reliability concerns and certain business procedures, credit risks, and also physical delivery. These risks when absorbed by the operating utility could increase the overall operational costs. Consequently numerous components must necessarily be considered in the overall cost equation.

With respect to the effect on grid reliability, to the extent that generation that might not otherwise be available is made available for economic dispatch, reliability would be enhanced. Of course, economic dispatch must be facilitated subject to the constraints of reliability criteria, both by the standards that exist today and those that will be established by the reliability organization or those that will be created out of the Energy Policy Act.

Economic dispatch -- and let me emphasize that -- economic dispatch should always be secondary to reliability dispatch.

PacifiCorp believes that economic dispatch will provide the greatest benefits to customers when the process is transparent to all of the market participants, and that when resources are dispatched on more of a regional basis as opposed to a utility-by-utility basis. This is one of the reasons that PacifiCorp and several other utilities in the Northwest have proposed creating Gridwest. Establishing an independent operator of a consolidated control area with a security constrained economic dispatch as we envision under Gridwest would expand dispatch opportunities for all participating in the Pacific Northwest and the Intermountain West, including non-utility generators.

That said, even in non-ISO or RTO regions economic dispatch could be enhanced without impairing short-term reliability if non-utility generators entered into a contractual commitment to provide energy to the utility for a specific time period of time consistent with the utility's unit commitment process and protocols. But it would be inappropriate in our view to put state regulated utilities in any position where they are required to purchase power from a non-utility generator if that generator has the ability to make an unconstrained unilateral decision whether or not to provide energy to the utility, or, alternatively, to participate in other markets that may provide a better price for their energy at that point in time.

Further, given that the primary obligation of a utility like PacifiCorp is to provide service to native load customers, non-utility generators must recognize that there is a tradeoff for being selected to be economically dispatched by the utility to meet the needs of native load customers. And non-utility generators must be willing to potentially be subject to contractual non-performance penalties for failure to deliver when dispatched by the utility.

To be fair to all stakeholders and yet still be effective, any regulations that would be developed to foster greater inclusion of non-utility generation in a state regulated utility dispatch process must be balanced in order to satisfy those above concerns.

As this joint board contemplates the possibility of recommendations for the Commission's final report to Congress we would hope that you would proceed in a manner that avoids undermining the ability of jurisdictional state

Commissions to effectively oversee the utilities' dispatch decisions.

And I very much appreciate the opportunity my company's views on this important issue.

COMMISSIONER KELLY: Thank you, Doug.

Doug, when you said that more forward contracts would increase the pool of generation for efficient dispatch but that there should be a reciprocal obligation on the part of non-utility generators to make their power available, were you thinking of any specific time length?

MR. LARSON: No, not necessarily. I mean I think, you know, as long as there is a fixed period of time that you can count on that third party to provide power, I think that's fine.

The area that we probably have the biggest concern is the one I mentioned in performance. And, you know, to the extent that we have an obligation to serve and if we don't get power that we're expecting on a contracted price and have to go to the markets, it's that differential, the spread that we pay that somehow you've got to be compensated for to protect native load customers.

COMMISSIONER KELLY: And can you give us an estimate of what percentage of PacifiCorp's energy is produced through contracts with third parties, with non-utility generators?

I guess I shouldn't say that. I guess you might consider Bonneville to be a utility generator.

MR. LARSON: Well, I mean, you know, obviously we own a huge portion of resource. I mean it's probably somewhere in the, I would say, 8000 megawatt range. And it changes all the time. I mean there's a chunk of it natural gas, probably 65 or 70 percent of it coal fired generation. Contracts, you know, I mean the BPA peaking contract, I'm trying to remember the magnitude of it these days. I mean about 1000 megawatts.

But I think the bigger issue for is when you're out in the market buying resources, especially for a utility that is, you know, peaking, you know, and you buy a 16 hour block and have to sell it off in the shoulders. I mean we're in the wholesale market every hour buying and selling. So there is a fair amount of -- large number of transactions in the wholesale market.

I don't know if that answered your question or not.

COMMISSIONER KELLY: Thank you.

Does anybody else have a question for Doug?

Yes.

MR. KAHN: Commissioner Kelly, Robert Kahn. I just want to express a, since I'm at the end of the queue, I want to express a concern regarding our time management.

COMMISSIONER KELLY: Yes.

MR. KAHN: I'm prepared to speak for five minutes, but I really do want to at least speak for five minutes, particularly in light of the comments that were just made by my colleague from PacifiCorp.

COMMISSIONER KELLY: Thank you, Robert.

COMISSIONER BACA: Commissioner, I just had a quick question.

To understand something you said, Doug, when you were talking about regional bases instead of a utility-by-utility you said Pacific Northwest and Intermountain West or northwest?

MR. LARSON: Intermountain West. So basically Utah, Wyoming, Idaho.

COMISSIONER BACA: Okay.

MR. LARSON: I mean we kind of break our system into an east and west control area.

COMISSIONER BACA: Okay. I just needed to make sure I understood that geography. Thank you.

COMMISSIONER KELLY: Thanks, Shirley.

COMMISSIONER SMITH: Doug, you said a couple of things; I'm wondering how they fit together.

I thought I heard you say that access to information is key in terms of transparency, having information. But then if this is real time how do we secure sensitive information because my -- sitting on the WEC board it seems we spend a lot of time talking about access to information and everybody thinks that the real time information -- which I assume is what's being used in these hour ahead dispatch decisions -- is something that nobody wants to share.

How does that fit together?

MR. LARSON: Well, I think that -- I mean that is the area that's problematic from my perspective, at a distance anyway, not being somebody that sits on the trading floor. I mean it's fairly intuitive that if you're in the Cal ISO where it's market based you put in a bid, you can dispatch fairly easily.

Within our stacking of resources obviously we know the cost of each one of the thermal plants all the way up the stack. That information is proprietary to us and we know exactly what it is. On some of the other resources that get dispatched, you know, at least within our area, you know, third parties aren't really that interested in sharing their cost information.

And so I'm not exactly sure how you would fit folks into the queue where the entity that is in charge of dispatching up that stack really doesn't know the cost information. And so that's where it fits in with, I guess, my comments that if you somehow could have entities that would bid in on a marginal cost basis so that you actually knew the cost -- or, you know, at the price that they wanted to be dispatched at, I think that could, you know, fit well.

I mean we have contractual arrangements where certainly non-PacifiCorp generation is dispatched, you know, in the queue based on contractual terms, QFs and all sorts of others that we have arrangements with.

COMMISSIONER SMITH: My other question was you kept saying several times about state regulated dispatch procedures. And I'm wondering in what way -- are you talking about state Commissions? If so, in what way is my Commission regulating your dispatch procedure?

MR. LARSON: You regulate it regularly.

Actually every time that we prepare a report and your auditors from the Commission come and look at our power cost models, you know, within those power cost models they're dispatching all of those resources. They look at our fuel costs, the coal costs.

COMMISSIONER SMITH: I wasn't sure if that somehow tied into the IRP. But that seemed pretty far removed.

MR. LARSON: No, it's not really in the IRP; it's in the power cost model. And it's heavily scrutinized.

COMMISSIONER KELLY: Thanks, Doug.

Our next speaker is John Coggins. John is with

Salt River Project where he is the manager of supply and trading.

MR. COGGINS: Good afternoon, members of the Board. Thank you for the opportunity to be here this afternoon.

I thought I'd start off just with a quick overview of the Salt River Project. The Salt River Project has been in existence for over 100 years. We are both a water and power utility. The power district of SRP is a political subdivision of the state of Arizona. We have an elected board that provides regulatory oversight of SRP.

SRP serves on the electric side a little over 850,000 retail customers. We have a summer peak load of over 6,000 megawatts. Our generation resource portfolio consists of a number of different types of fuel, including nuclear, coal, natural gas and fuel oil. We also have a small hydro system that we operate near the Phoenix area. And, of course, we have long term and short term purchases and renewable energy resources.

SPR does have a native load service obligation as required under state law. Our board -- we've talked a little bit about oversight of dispatch practices. Our board has mandated that SRP seek to provide the least cost electric service to its native load, and that philosophy then of course impacts the economic dispatch policies.

Taking a quick look at our dispatch philosophy and some of the procedures at a very high level. SRP does dispatch its own generation assets and procures power in the wholesale market to serve customers at least cost. We employ various models in the forward or the long term, day ahead, and real time markets to perform economic dispatch. These models consider a variety of things including fuel costs, fuel deliverability, heat rates of units, unit start-up costs, transmission or delivery costs, environmental issues, hydro system conditions, and of course wholesale market opportunities.

These models also take into account existing physical and financial contract obligations.

Economic dispatch at SRP is performed by the merchant function of SRP. But dispatch decisions may ultimately be adjusted in real time in collaboration with the reliability function of SRP in response to various system constraints.

System constraints could include things like transmission availability -- usually it's changing transmission availability is what I'm referring to -- import capability -- the Phoenix metro area is a load pocket and is import-constrained -- voltage constraints, unit operating characteristics. All of these are factored into the final dispatch decision.

Some key points that SRP wanted to make today, three of these affect economic and operational matters and two are more associated with regulatory concerns. First of all, at SRP we believe economic dispatch is working and has worked for a number of years. We have consistently managed our resources to provide safe, reliable and cost effective service to native load customers. Our rates are among the lowest in the region.

SRP also believes that economic dispatch is working throughout the western region. The robust wholesale markets in the west support and facilitate the integration of utility and non-utility generation dispatch. Market efficiency and transparency has improved through the development of electronic trading platforms, physical trading hubs, and the available of financial products and services.

I might pause here and say that early on there was a question about changes in the wholesale markets and how things have evolved from past times when it was more economy sales and purchases. And I think one of the areas that it's changed the most is in fact the availability of financial products both in the electricity markets and natural gas markets. And associated with those products also new types of counter-parties -- primarily I'm referring to large financial institutions that are available to help with hedging practices in the electric markets and the gas markets.

One of the concerns we have relative to I'll call them standardized rules and regulations that might be applied homogeneously across the nation are that in fact we believe that this could potentially increase costs to customers and/or decrease reliability. Given the very large number of variables that go into the dispatch decisions we think there is a high potential for unintended consequences, again trying to have a more homogeneous approach to dispatch.

An example of an unintended consequence may be to be focused on one particular variable or characteristic at the expense of others. And one that's commonly mentioned, of course, is heat rate or thermal efficiency. And a focus more singularly on that characteristic as opposed to others may create problems.

From a regulatory perspective, as my colleague at PacifiCorp mentioned, we believe the state and local regulatory agencies should retain oversight for economic dispatch. This is because we believe that economic dispatch can have a large impact on customer rates and oversight at the state and local level, where accountability to the customers is the strongest, seems to be the most appropriate from SRP's perspective.

And finally, I just wanted to comment that SRP does not see a need currently, or a compelling reason for a strong federal involvement in these issues for the reasons that I've described.

That concludes my remarks.

COMMISSIONER KELLY: Thank you, John.

Any questions for John?

(No response.)

COMMISSIONER KELLY: You're off the hook for the moment.

MR. COGGINS: All right. For now.

COMMISSIONER KELLY: Our next speaker is Kieran Connolly. Kieran is with the Bonneville Power Administration where he is manager for regional coordination.

Thanks for being here.

MR. CONNOLLY: Thank you.

I have a little package here that I think folks have that I brought. And I wasn't quite sure where this conversation was going to go today so I'm not going to go through it point by point -- for one reason: because I don't have time in five minutes. But there were a few issues I wanted to hit and we may want to flip to some of those things based on any questions that folks may have.

As some of the other speakers have alluded to with regard to the Northwest, I think the existence of the significant level of hydro resources we have in the Pacific Northwest has really helped define the history of dispatch in the Northwest. Hydro represents even today 40 percent or more of the generation base. And, of course, that varies significantly with hydro conditions. And so we've had a long history of when the hydro runoff is high you need to find a way to displace resources, because that water coming down the river is a relatively cheap fuel. And so there's a long history with PacificCorp and others in the Northwest of finding ways both formally to coordinate and cooperate on that and then through bilateral markets to take care of it.

Only about 30 percent of the annual runoff in the Columbia River basin can be captured in the form of storage. This is different than a lot of other hydro systems elsewhere that have significant storage in excess of the runoff that they have. So there's no real ability to carry water over long periods of time in the Columbia River basin.

And we also see significant impacts between projects because you've got upstream projects based on the amount of water they release and in fact the fuel that's available to the projects downstream. You also even have issues with some of the projects that are closer together. The downstream project, if they're storing water, actually affects the ability of the upstream project to generate because the water backs up toward that higher dam.

And because of all these impacts we have a number of agreements that we've had over time. The Columbia River Treaty with Canada, PNCA amongst parties in the United States, Hourly Coordination Agreement with the Mid-Columbia Hydro-Thermal Coordination, and all of these agreements have existed to basically try to extend the economic dispatch beyond a single utility, particularly with regard to the hydro system.

And one of the other effects we've seen over time is that -- at least particularly for Bonneville in 1980 when the Power Act was passed -- that a lot of the transactions that were going on under PNCA actually migrated into the bilateral market. And we actually sort of institutionalized that PNCA in that it was called the 1997 PNCA -- although it took us about seven years after 1997 to get it put in place -- to basically transition folks to the point where the PNCA worked well with the bilateral markets and the pricing that we saw there.

So based on all of those, resources today are dispatched on the hydro system first to meet the non-power constraints. And those non-power constraints range everything from navigation and flood control to fishery needs that we have for the water. And to the extent that there's flexibility beyond those non-power constraints, that's where the dispatch turns to economics.

And there was a question asked earlier about whether or not folks keep track of those economics, have programs for tracking them. So on the hydro system clearly we have models that we use to help us factor in the economics of how much water we think we can push into heavy load hours, how much water we think we need to hold onto for early or later on in the month.

But there also are significant uncertainties we have to deal with with regard to these non-power constraints. And when you're dealing with water coming downstream you've got significant inflow issues to deal with, what's really going to show up in the next hour, the next day, the next week in terms of precipitation. You also have to take into consideration load uncertainty.

So you also have to bring in a mix of operator experience where you say just how close are you willing to drive the hydro system on that particular day because again those non-power constraints, we basically treat those as absolutes. We do not want to violate them. So some days you drive right down the middle of the road; other days when things are shaping up pretty well you can run a little bit closer to the edges.

And that portion of the economic dispatch I would suggest today is still more in the realm of operator judgment.

The availability of transmission to facilitate this dispatch has also been an issue in the Northwest. Historically we've seen a lot of short term availability of firm transmission; and actually even in the Northwest non-firm transmission, because it's treated firm within the hour, has been available to serve load. And that has really facilitated the dispatch. So as conditions change very rapidly on the hydro system folks were able to go out bilaterally and make transactions to either displace other resources or to export or to bring power into the region.

We did see a growth in transmission constraints on the system between, say, 1995-2001. Now those are still relatively sporadic compared to other parts of the country. But it did definitely cause us concern because again this hydro system operates really as a whole system. So if you start having internal constraints on it, and if those run into your non-power constraints, you've got a real problem because you basically have two issues that you do not want to violate basically running smack dab into each other.

One other thing -- Bonneville has undertaken two efforts in that regard. One is an infrastructure improvement program to relieve some of the constraints through building and through non-wire solutions. And we're also putting in place a flow-based ATC methodology to help translate better the constraints that remain again out to that bilateral market so that it can take it into account.

And that's my comments. I guess I'll open up for questions.

COMMISSIONER KELLY: Thanks, Kieran.

Any questions?

(No response.)

COMMISSIONER KELLY: Kieran, I understand that Bonneville has looked at the possibility of Grid West or TIGs proposal or conversions proposal. I really don't want to get into the merits and demerits of each of them. But is there something about that endeavor of looking at transmission more broadly that relates to increased dispatch or increased economic dispatch?

MR. CONNOLLY: Well, I probably am not the best person at Bonneville to ask about that particular issue. I haven't been working on Grid West. I worked on RTO West several years ago. So my thoughts are probably a little bit outdated.

But definitely I think Bonneville saw benefits in the convergence proposal that we supported that could be applied across the region. We still think those benefits are there. We are also --

COMMISSIONER KELLY: Are those dispatch benefits?

MR. CONNOLLY: They relate to dispatch benefits, because certainly we were envisioning in the consolidated control area under Grid West attempting to basically spread the use of the best resources across a wider area.

Obviously, you know, as other folks have mentioned, there's complexity that goes with size. And I don't think Grid West had gotten to the point yet of figuring out exactly where the balancing point in all those things was. But certainly that was one of the benefits we were looking to find.

COMMISSIONER KELLY: Okay. Thank you.

COMMISSIONER SMITH: Is there a way that the coordination in the dispatch that you described on the hydro system interfaces with the thermal units that also get dispatched over this transmission system?

MR. CONNOLLY: Sure.

So with the hydro system what you're basically looking at -- because you do have a temporal problem particularly with downstream projects, so you don't want to be releasing water from your highest project on the river on Friday afternoon if it's got to flow through downstream on Saturday and Sunday if the prices drop off then. So you're -- So basically you balance first -- at least from Bonneville's perspective we're balancing first on the hydro system.

We consider the discretionary water when we do have it on the hydro system is a pretty low cost resource, and so we want to operate that. But then you turn to thermal resources at the same time and you're looking at the future value of that water. And then you go to displace thermal resources or buy from thermal resources in order to fill in to meet your load.

COMMISSIONER SMITH: So does Bonneville do that?

MR. CONNOLLY: Yes. So Bonneville --

COMMISSIONER SMITH: Or do you coordinate with others in the region? I guess that's what I'm trying to get at.

MR. CONNOLLY: Yes. We coordinate with others in the region both in terms of agreements we have that last over time and then also just through the bilateral markets.

We're heavily involved in both the day ahead and the real time market to bring our system into balance. We have to make balancing purchases to make our preference customer commitments and then we're also selling the surplus as necessary in order to meet those non-power constraints.

COMMISSIONER SMITH: Okay. Thank you.

COMMISSIONER KELLY: Thanks, Kieran.

Our next speaker is Marcie Edwards. Marcie is with Anaheim Public Utilities where she is general manager.

Of course she has a breadth of experience with utilities in California. She has also headed up the

California ISO. And you were at the Los Angeles Department of Water and Power before that, right?

MS. EDWARDS: Yes.

COMMISSIONER KELLY: So thanks for being here.

MS. EDWARDS: I appreciate that.

Interestingly enough -- and it is part of what makes this discussion so entertaining to me -- is that I also was a generating station operator and a power systems operator. So there's more agendas than Carter's got little pills when you start to talk about this topic.

COMMISSIONER KELLY: Right.

MS. EDWARDS: First of all, I am from California. And that is the original state of unintended consequences. So as entrepreneurial as I have a wont to be, I would certainly advocate a level of caution in something that has such a significant driver to our industry overall.

A few quick comments about cost. While lowest cost to the customer is an absolutely laudable goal and not one that I can disagree with under any circumstances, remember too the dynamics of who owns what in this system. There are also a lot of stockholders involved. There is no guarantee that savings flow back to the customer. There's a number of stakeholders involved in this. And so just something to bear in mind.

Secondly, the intent is to create greater efficiencies overall that can be shared by everyone. However, much of what could be considered when you look at economic dispatch is more a shell game. You can save two bucks over here but you're going to cost this entity four bucks over here. And trying to determine the net net across literally multiple industries in varying points in the supply chain is a very challenging exercise. And so you do create haves and have-nots with this focus on really what is economic dispatch. The question is always going to be economic to whom.

Quickly, Anaheim is a very small agency when you compare the size of what's been spoken of right now, a small municipality. We are a participant in the California ISO. Our history was such that we bought control area services from Edison. And when Edison joined the ISO, much like the flea that rides on the dog, we went along too.

It's been a very interesting exercise trying to embrace market based systems when you were raised in the older merit order type of a dispatch arena. And it's been both a combination of advantages and disadvantages, not the least of which, the smaller agencies are what they are. They're smaller agencies. They're a little easier to swamp than some of these who have, you know, hundreds of millions of dollars in assets. So it's been quite a wild ride for some of the smaller participants.

Taking a quick look at the economic dispatch question overall: You've heard about hydro. The summation of hydro is that they look at energy generation as a byproduct. And trying to integrate those concerns into a massive water-based environment that's been going on in some instances prior to when we had lights is always going to be a challenge. There may be opportunities, but it is -- the limitations of hydro are very significant.

If you look at generation, we talked about the physical limitations of generation. In addition there's a lot of peculiarities with generation. Generation, as an example, that can go up to one level and then has to go up another 40 or 50, well past an economic point, because that's just the physical characteristic of the machine.

You heard a little bit about start times, stop times. And just from an observation standpoint, while the ISO has now had some practice in signaling its participants in how to move their generation, it's still very difficult -- just that limited window -- to be able to respond appropriately. They're still fine-tuning the software and the signals and trying to recognize the differences. And we're just talking about the small pool that are receiving the signals to move up and down.

So, again, kind of a cautionary note about the true complexities associated with doing something like this.

In addition to the plant limits -- and this comes back under the robbing Peter to pay Paul scenario -- one of the issues you get into is excess wear and tear. If you operate a unit, particularly, you know, we've got thermal units that are 30, 40 years old. If you operate them outside of their normal comfort zone they break earlier, stay broken longer. And whose responsibility is that? They push them into that range because it's economic for ten minutes and it breaks for three days. That's not a net positive for anyone overall. And that's something, too, that you have to be fairly sensitive to.

Also the issue with the power system is that as much as you plan it will always surprise you. And if you use all of your energy -- and let's say you're talking about hydro or you're talking about plants that are more fully depreciated or energy that happens to be cheaper for some number of reasons -- you use it earlier in the day, very likely you're going to get into scenarios later in the day when you have less of a fallback position when you really wish you would still have that energy available.

So a lot of this, while it's not immediate reliability based, there are some significant timing considerations that you have to bear in mind. And if you are following a tight economic paradigm I can see where that would be fraught with some significant problems.

Also broken units or units that are otherwise disabled, you want to just leave them alone. And it seems as if, well, that would be inherent, of course you would leave a broken unit alone. You don't want to risk tripping it. Well, as I said, just the software associated now with moving units up and down doesn't recognize all the limitations. So again, important to bear in mind.

And if anybody thinks they're going to raise and lower nuclear units, I'll wait here while you talk to the Nuclear Regulatory Commission because that's not going to be -- that's something else it isn't very likely it's going to occur.

System limitations. There are so many more than transmission that it's not humorous. You heard a little bit about -- great jargon -- system inertia requirements, voltage requirements, nomogram limitations. I can go on and on and on and on. But the point is the complexity aspects. Again, there are any number of them. And they are geographic-specific, region-specific, utility-specific. Very difficult to -- I love the word that I think John was using about a homogeneous solution. It can be very challenging to come up with any number of those.

Okay. Being sensitive to Robert's point that he wants to make sure he has an opportunity to make comments, I want to end with my thoughts briefly on what might be some of the homogeneous fixes.

One is to keep the conclusions and subsequent structure that may flow from a federally based organization extremely flexible and sensitive to the needs of the states in particular, as well as the local agencies who act as regulators, similar to the state utility Commissions.

Anything that's a voluntary aspect will allow us to prove out the validity of some regulatory paradigm. If you put forward this set of standards, you make it voluntary, the people who work within it will show you the benefit; those that don't, then you have a concrete way in which to determine, well, that wasn't workable and here's why, rather than imposing it and then dealing with all of the unintended consequences. So I would certainly endorse both a focus on the state, regional, and lower levels as well as anything that's done being of a voluntary nature.

Thank you.

COMMISSIONER KELLY: Thank you, Marie.

Questions?

Dian.

COMMISSIONER GRUENEICH: Yes.

Marcie, you describe that the City of Anaheim ended up coming into the ISO because it had previously been within Edison's control area. Looking back on it, do you think that there were greater benefits for the City of

Anaheim in the city before when it was just basically dealing directly with Edison in the more traditional merit order approach in terms of both overall cost impacts on the customers as well as -- what will turn into cost impacts as well as the other things that you've talked about, the wear and tear--

I mean since Anaheim has essentially been in both systems and you've talked about, you know, a lot of the difficulties with the ISO, has there been any quantitative or just sort of gut level feeling of when it comes down to the actual cost-benefits, the costs or benefits, how does it come out in your mind?

MS. EDWARDS: I'll break it very quickly into two boxes: cost and then stability/reliability.

From a cost perspective what I used to buy from Edison for 300,000 a year I know buy from the ISO for nine million a year.

There were other shifts in the paradigm that allowed me -- specifically the one where you put in all your costs and then you pay an average fee to use the grid -- there was some net benefit to me. So my net loss, if you would, financially, is only about two or three million dollars a year.

But you have to understand: There are so many dynamics changing in the system over the last couple of years because so many things were changing simultaneously that it's hard to separate out what was simply the cause of the ISO or what would have happened otherwise.

From a stability/reliability perspective, arguably it was more reliable before, if you gauge reliability from frequency and duration of outages for varying reasons. But again, I wouldn't lay that at the ISO's doorstep because they're cooking with the ingredients that they have been given.

This has been a very volatile situation in California. And the ISO more than once has been in situations where there were simply no good answers. So it's argued that they have done a yeoman's job with what tools that they had at the time.

But I look at every outage that, you know, California encounters and I try to understand the root cause and the implications and what could or couldn't have been done differently. And a lot of it is just the volatility. We just undertook so much change at one time and so many unintended consequences. The feds had a view, the states had a view, regions have a view, all of the participants have different views. And all of that interaction created an unstable situation as a whole.

Moving forward, it remains to be seen with some of the new market mechanisms that the ISO wants to impose, if they improve, if they're ambivalent, or if they create significant unintended consequences on their own. And the next couple of years is going to prove that out one way or another.

COMMISSIONER KELLY: Mark

COMMISSIONER SPITZER: It sounds like you've been a few different worlds. So I'd like your reaction to the underlying economic issue, which is a distinction between a new plant with a higher efficient heat rate versus the fully depreciated plant owned by, let's say, a public or an IOU. And you could analogize to the new fuel efficient car versus the old one that's paid for but less efficient.

How does your analysis vary based on where you've been and particularly where --

MS. EDWARDS: It depends what you put in --

COMMISSIONER SPITZER: -- you are now, but compared with the IOU model or some other.

MS. EDWARDS: The efficiency equation is one that's being rewritten now by everybody.

It used to be when you said, well, incremental cost, you knew you were talking about heat rate and fuel cost. But now there isn't really a standard, per se. Do you put in a component for wear and tear? Do you put in a component for all of the start/stops? Some people do, some people don't. Do you put in a component that pays back your investors for over the 30 years, let alone the marginal discussion? Where are you supposed to recover your return on investment components?

So I know just off the top of my head of six or seven ways people figure this out differently. It's always better to have a level of developing more efficient generation. You know, without a doubt there's some significant value there just because you're getting more from less. But we're still not at a point that we can not adequately compensate those generators that are older because we still need them in the mix, at least in the California paradigm, very much so over the next term.

So until we get to a point where there's literally competition within the generation sector it's going to be very difficult to differentiate yourselves. There will be units that are extremely efficient that don't run because of where they are, how fast they can get on, what their operating characteristics are. You know, there's a bunch of different reasons. So it would literally be case by case.

When you're asking about this unit's going to run, you would have to tell me where is it going to be, what fuel does it run, what operating characteristics does it have. And that's what will really determine to what extent it plays into the market or not, not just its relative efficiency to an older unit.

COMMISSIONER SPITZER: But Commissioner Kelly discussed the quantitative versus qualitative. And you've raised a bunch of very legitimate issues. But isn't there a means -- or do you currently use a means of monetizing those in an effort to turn some of the qualitative into directly measurable?

MS. EDWARDS: There really is no standard of monetizing it. And, you know, who you are would depend on whether you thought that was a good idea or not.

There are some agencies who you want to run your plant -- let's say you have it on and you know you're going to need it tomorrow. But you need to keep it on and you want it to play into the market for at least the next couple hours -- again California paradigm rather than a merit order -- you're going to drop its price so that it continues to play and you get some sort of revenue on it for some number of hours, because you're looking forward a day, a day and a half.

I would be concerned if we tried to systematically define a recovery structure for every plant, that -- it would be very difficult to do because the value is in the eye of the beholder. It depends what else is in their portfolio how valuable that facility is or isn't to them.

It's kind of back to that -- and I don't mean shell game in the negative sense. But as I listen to people talk I can hear it to where, yep, this sounds great and it's reliability-oriented but it saves that company money by forcing a greater expense outside of their boundaries given their portfolio development. How do you quantify that?

COMMISSIONER KELLY: Marcie, how about the bid-based market? Does that do a better job of quantifying it?

MS. EDWARDS: In some ways. But it -- My issues with the bid-based market are the outrageous complexity -- and it gets worse every minute -- the investment it takes to handle it when you go to these ten minute markets and to what extent is it worth it; the fact they can't respond in a way that acceptably works with the limitations of each of the providers.

It also doesn't do much about signaling anything long term. It just reflects people's -- the challenges associated with systems, really, in real time in forecasting load and forecasting outages. So it doesn't fill that gap. So how much money do you want to put into it to fine tune something that you would hope is only going to address a small portion of a real time market.

From that standpoint really both systems work well. It depends how much you have in the forward and contract markets and how much exposure you have in real time. The smaller it is the more either system, frankly, will work.

COMMISSIONER KELLY: Thank you.

Any other questions for Marcie?

(No response.)

COMMISSIONER KELLY: Thanks.

MS. EDWARDS: I brought a hand out and I'll have it available of some of the remarks we brought.

Thank you.

COMMISSIONER KELLY: Great Do you need copies made?

MS. EDWARDS: No, I have plenty.

COMMISSIONER KELLY: You have copies?

MS. EDWARDS: Like 50 of them.

COMMISSIONER KELLY: Great. Do you want to just pass them around here to begin with?

MS. EDWARDS: Well, I don't want to take away from our next speaker so that people --

COMMISSIONER KELLY: Okay.

MS. EDWARDS: -- aren't reading them, because I always hate when they do that to me.

(Laughter.)

COMMISSIONER KELLY: Appreciate that.

And our next speaker is Richard Kurtz. Richard is with the Arizona Electric Power Cooperative where he is vice president of power services.

Thanks, Richard.

MR. KURTZ: Good afternoon. I thank you all for the opportunity to be here. For a small generation and transmission cooperative to participate in a forum like this is a very unique opportunity for us.

COMMISSIONER KELLY: Richard, can you speak closer to your microphone?

MR. KURTZ: Yes, I can do that.

COMMISSIONER KELLY: Thanks.

MR. KURTZ: I want to start with just a very brief description of AEPCO and the load and resources that it manages.

And we are a generation and transmission cooperative. We operate out of Benson, Arizona. Our load is comprised of basically six member distribution cooperatives and a few long term contract sales, ones with Salt River Project. And we are about one-tenth the size of Salt River. We're looking at about 600 megawatts of system resource dispatch.

Our resource system consists of two coal units, coal-fired generating units of about 350 megawatts total -- which is about 53 percent of the capacity of our system -- and we have gas fired units that represent about 30 percent and we have some long term purchased power arrangements with

IOUs and with non-utility generators.

We think that as far as where we are with renewables, et cetera, we're in the middle of that with our state regulatory Commission and determining that we'll have some solar power in our portfolio and some other renewable generation in our portfolio down -- in the future.

Right now we administer demand side management through our load cooperatives, through our distribution cooperatives, who have basically interruptible tariffs in place for irrigation loads. We serve most of our cooperatives serve small municipal areas in southeast Arizona and in rural communities. And we're in and around Tucson and to the south and east of there, and we have a cooperative that's in northwest Arizona as well that serves in the vicinity Bullhead City.

As I said, our total load is around 600 megawatts. And we do have two large coal-fired units, relatively, for our system that serve basically 80 percent of our energy needs. Something over 80 percent is coal fired and is very well priced relative to the market.

We do economic dispatch on a daily prescheduled basis. We operate in the same regimen as John Coggins has indicated with Salt River with respect to how we look at and obtain daily resources and how we do our daily resource dispatch.

Aside from our coal fired units which are base loaded and run all the time, given their economics, we have 133 megawatts of gas turbines of varying heat rates. We have one newer gas turbine and we have one that's very old. And the heat rates run from pretty efficient to, in today's standards, to very, very inefficient.

When we do economic dispatch we poll the market. We poll the market daily. We are constantly in the market for, based on our load forecasts for the prescheduled day, constantly in the market for the resource next day that will not -- that will allow us not to operate our gas turbines at today's natural gas prices. A very considerable effort goes into all of that. And we end up then with an economic dispatch regimen that helps us control our costs and keep our member rates at their lowest.

One thing I would like to point out -- and I know you all are aware -- but as a G&T cooperative our members are owners. Our members are -- How we satisfy our members is through providing them with the lowest rates possible.

We are a -- As a G&T cooperative there are many G&Ts that are not regulated in their state. In our state we are subject to the regulation of the Arizona Corporation Commission.

Finally, I don't want to spend a lot of time covering ground that my colleagues here to my left have covered, but I do want to emphasize a couple of things that I heard, in brief that I think consider maybe deserve a little more attention.

One of those things -- and as being one of the folks that are involved in resource acquisitions I'm very familiar with this at our cooperative -- is that economic dispatch begins with long range planning. We've been in the market over the last five years for purchased power agreements, basically summertime peaking resources, to cover growing loads of our distribution cooperative members. We have been able to enter into contracts with both NUGs and with IOUs in order to resolve our resource shortfalls.

We look at those contracts and formulate those contracts based on the belief that that energy that comes from those contracts must be dispatchable in our current and existing generation system. And so we try to make the terms and conditions of those contracts match as best we can the day-to-day operation and dispatch needs of our loads. That's one idea that I haven't heard a lot about here.

Secondly, I would offer that -- and I did hear a touch on it from PacifiCorp: Credit. Credit issues, credit requirements on a 100 percent debt cooperative can be very onerous. We've had to deal with those through imaginative and creating contracting with the counter-parties that we deal with. We are not a credit rated G&T cooperative. And

I believe Commissioner Spitzer could tell you that we wouldn't be one if the credit people came to look at us to determine our credit-worthiness. So we've had to deal with those kind of issues through creative contracting. And it's been an interesting process.

The third thing that I heard touched on today, which has been something that we've spent a lot of time concerned about, is the marketplace rules. How do those rules play into our economic dispatch. And obviously today's rules are a lot different, and I heard Mr. Hinckley touch on that earlier.

The pre-1995 world was a lot different than the 2005 world when it comes to economic dispatch. In those days there was a free flow, if you will, of folks trading with one another based on cost-plus and split-the-savings on energy production costs. Those things exist today to a much, much smaller degree.

What you've got now is a whole different market-pricing regimen -- and our gentleman from PacifiCorp and SRP touched on it -- that deal with market prices and who you're dealing with and trading for on a day to day basis, and how many times that power has been sold and resold before it gets to the load-serving entity.

So those are the issues that I've heard touched on this morning that I would like to just say we have studied and taken into account in how we do our economic dispatch, both short term and long term.

Unless there are any questions I will pass the microphone to Mr. Kahn.

COMMISSIONER KELLY: Richard, how much of your power do you procure by contract?

MR. KURTZ: We have -- On a capacity basis right now in the summertime we have 104 megawatts under contract out of about 612. So somewhere around 15 percent as a rough number -- capacity-wise in the summer.

Energy-wise -- In fact there's a handout posted on the website that shows our 2005 -- I believe it's on the FERC website or will be -- that shows our 2005 energy production. We're getting about seven percent out of long-term contracts. And the difference between capacity and energy being that the capacity contract, the major one we have with a non-utility generator, is for summer season only. So it's not an annual contract.

Does that answer your question?

COMMISSIONER KELLY: Yes. Thank you.

Any other questions?

(No response.)

COMMISSIONER KELLY: Our next speaker, you have plenty of time, Robert.

MR. KAHN: Okay.

(Laughter.)

COMMISSIONER KELLY: Robert Kahn, the executive director of the Northwest Independent Power Producers Coalition.

MR. KAHN: Thank you very much. I very much appreciate the opportunity to be here today.

I represent the Northwest Independent Power Producers Coalition -- we call ourselves NIPPC -- and we represent 3600 megawatts of operating capacity in Oregon and Washington. One-third of that, by the way, is coal generation and two-thirds of it is combined cycle. And we have an equal number of megawatts in development in Oregon and Washington and in Idaho.

But I think I can also speak at least generally on behalf of independent producers in this geography that, you know, Mr. Larson referred to, which is the Northwest and the Intermountain West. This is an area that is largely served by the Northwest Power Pool and is the footprint of Grid West.

And just to give you a sense of proportion, it's within this territory that Bonneville, while very significant, represents 35 percent of the high voltage lines as opposed to its position in the Northwest where it is 75 percent.

In any event, this is the territory we're talking about. And independent power producers both thermal and renewable represent roughly 18 percent of the generation in that territory that I'm talking about.

Our message in essence is that IPPs are not included in hourly markets. Longstanding institutional structures have prohibited merchant participation. When IPPs are called it is only as a last resort. It should come as no surprise that NIPPC supports the formation of an independent transmission provider, an ITP for our region.

Economic redispatch is constrained but not by physical software or resource hurdles, although these do exist. The problem I suggest to you is institutional congestion. We have in this terrain 15 control areas. And in a transmission version of a tragedy of the commons, each control area pursues, as one would expect, its own optimal objectives, sometimes to the detriment of its neighbors and frequently to the detriment of the integrated system as a whole.

Institutional congestion yields several real consequences. I'll give you a couple of examples.

First, redispatch is increasingly managed -- if you want to call it that -- by curtailment which occurs without regard to economic consequence.

Secondly, underutilization of readily dispatchable generation for the sake of control area priorities and, let's say, traditional inter-utility transactions to meet balancing requirements.

Some of our projects, incidentally, are very strategically located. I like to say that our large generator at Centralia, which is half-way between Portland and Seattle, isn't called Centralia for nothing.

Third, there is a general mis-utilization of transmission capacity. So for example, an obfuscation of actual ATC -- available transfer capacity -- due to contract rights that can be withheld and are withheld, thereby eroding efficient operation.

And finally, four, confusion over what is advertised and what actually happens reigns in our experience. So, for example, Bonneville's Oat Section 30.5 states -- quote:

"That the redispatch of resources shall be on a least cost non-discriminatory basis."

But our resources have never been formally dispatched by Bonneville's TBL -- its transmission business line -- and for all non-federal resources point-to-point service takes a back seat to network customers of the power business line.

We can resolve institutional congestion through control area consolidation. In fact, it's probably fair to say that control area consolidation is a precondition to economic dispatch. There are real lost opportunity -- measurable opportunities -- to this way of doing business in the Pacific Northwest and the Intermountain West. And one of the results of the exercise of Grid West was a peer reviewed cost-benefit study -- what we called the risk-reward study but it's a cost-benefit study. Although it was preliminary it was peer-reviewed. And if we were to assume that the deliverable of that entity, that ITP, was only to be economic dispatch and that therefore its costs of operation were limited to that function, the study conducted by Grid West released this summer would show it to be about $22 million a year costs.

And to take a look at the median assumptions -- because there was a spectrum of assumptions that people could choose from -- but if we were to choose from the median assumptions to try to arrive at the cost-benefit tradeoff of economic dispatch and we were to assume that ten control areas consolidated -- including Bonneville -- then we would see a $260 million annual benefit.

If we were only to look at four control areas consolidating then again, through the same metrics, we would say $84 million net benefit. And again, this is includes Bonneville, which represents 35 percent of the high voltage transmission grid in the area we're discussing.

So in summary, IPPs are left out of full participation in the hour-to-hour operation of the Pacific Northwest-Intermountain grid. If IPPs were fully integrated their highly dispatchable resources could be deployed to support, among other things, a competitive low cost ancillary services market, a competitive market for imbalances, including operational reserves, much better congestion management since economic dispatch is more effective as a tool to alleviation congestion than curtailment, and, to conclude, for the Pacific Northwest-Intermountain West as a whole the objective should be the realization of an ITP, an independent transmission provider, one that integrates systemwide operations and is capable of dispatching resources on a truly economic basis.

Now for Bonneville, if it should pursue for Bonneville, which has chosen not to proceed at least at the moment in the development of Grid West, we would hope that it would pursue a dispatch regime that takes full advantage of all of the plants connected to its system. This was the aim of Grid West and remains the aim of those market participants that are committed to proceeding with the ITP notwithstanding Bonneville's recent decision to drop out of the Grid West development process.

If you might indulge me very quickly, I'd like to use the occasion to respond to some comments from PacifiCorp.

IPPs would very much like to be under contract to our utilities. Unfortunately, as I sit here, only 12 percent of our capacity is under contract with the utilities beyond 2008. And this is, as spelled out, in the fifth power plan as prepared by the Northwest Power Conservation Council.

In terms of resource adequacy, we are limited, very limited in our export capacity to get to other markets. So we are in effect a free or relatively free reserve margin for the region, which might help explain why so little of our capacity is under long-term contract.

So, with that, I'd like to close again. Thank you for the opportunity. And I'd be happy to take questions.

COMMISSIONER KELLY: Thank you, Robert.

Greg.

COMMISSIONER SOPKIN: Robert, Greg Sopkin from Colorado.

This may come out of left field because I'm in the land of vertically integrated utilities and all-requirement contracts. But one of the concerns that our vertically integrated utility has raised is that with ever-increasing independent power purchases its seeing your credit rating as being affected in a negative way. And as a result, once this problem is addressed -- I mean the implication seems to be that it's going to need to do more and more self-billed if this problem isn't addressed.

Is this one of the reasons why you're only 12 percent contracted for? Do you have any solutions to suggest? And is this something that can affect economic dispatch.

MR. KAHN: Well, I don't know about it affecting economic dispatch. But since we have touched on Order 888 and the NOI today we probably could touch on the question you're asking as well.

What you're referring to is the debt equivalency issue or the balance sheet penalty. Much has been made of this issue by investor-owned utilities in recent days, recent months, maybe years. And while I will not claim to be an expert, I would suggest that you take a look at a recent order by the Utah Public Services Commission which address this in connection with QF contracts since they've done some interesting comments in this regard in their recent order. And also suggest that the impact of carrying the costs of a contract on a utility has far more to do with the utility's own credit standing and its own capital formation requirements than it does with the case of the IPP.

It's a very complicated set of metrics. And I would suggest maybe just by way of closing comment to offer to share a paper with you which we prepared and distributed to commissions in our area, and also to suggest that it's one of these things that, you know, like Marcie was mentioning, might be best understood from the perspective of that who is promoting the concept.

COMMISSIONER SOPKIN: Thank you.

COMMISSIONER KELLY: Dian.

COMMISSIONER GRUENEICH: Bob, you seem to be combining both the issue of what I think of -- can a utility do true merit -- true economic dispatch on a merit order by when it also has available non-utility resources or will it always to some extent favor its own generation. And you combine that with the issue of are there benefits by combining separate control areas.

And do you see those as inter-related or do you see that you could have a situation where -- Let me go back.

Do you see that -- basically is it your view that you just could never have true economic dispatch unless there is the independent transmission operator? And I'm wondering if you can comment on sort of how you view that issue versus what I think of as perhaps a separate issue, which is are there benefits to be gained in the world of economic dispatch by aggregating control of areas.

MR. KAHN: The sort answer to your question, Dian, is yes, I do think it's a prerequisite, at least it has been in our experience.

And do I see benefits in consolidation of control areas? I mean, we do. But probably more importantly, those who are operating control areas in our corner of the world have -- many of them have reached the same conclusion. And there are I think almost obvious benefits. And many of these start and must start with reliability.

You have an ability to see impacts that may cascade into your system if you have a wider view than you would otherwise not have if you didn't have consolidation. You also have opportunities to do dispatch that can avoid the kind of loop-flow impacts that Idaho is experiencing that can deal with some of these problems, which, frankly, I think are almost sometimes phantom congestion on the other side of the coin.

So the answer is yes. Do I think it's a prerequisite? It appears from prior behavior to be, yes.

COMMISSIONER KELLY: Robert, I think that I heard you say that there were two potential ways to increase economic dispatch at least of independent power producer power in the areas where you are: control area consolidation and an independent transmission provider.

Am I correct? Did you say that?

MR. KAHN: I think I'd like to suggest, Commissioner Kelly, that they are pretty much interchangeable in terms of my presentation.

COMMISSIONER KELLY: Okay.

How about more forward contracts? Is that also-- ?

MR. KAHN: Well --

COMMISSIONER KELLY: Or is that unlikely?

MR. KAHN: It's very plausible. Go back to what Mr. Larson said about the ability to have us on call, in effect, or at least that's the way I'd like to interpret it. It's a very good idea.

I won't bore you with my analogy of the idling taxicab. But we sometimes do feel like the idling taxicab waiting curbside for someone to use our services. And when they get in the cab, well, it may be expensive depending on how long we waited.

(Laughter.)

MR. KAHN: In any event, we would very much appreciate longer term contracts for any number of services that we can provide. But, frankly, there are a lot of services we feel we can provide if there is a market within which to provide them. And that doesn't have to be an energy market; it can be a transmission services market.

COMMISSIONER KELLY: Tom.

COMMISSIONER SCHNEIDER: So then is it the responsibility, really, of the state Commissions and the integrated resource plans or default supply plans and acquisition strategies that are going to build you into a long term market where the investment actually flows:

MR. KAHN: I think --

COMMISSIONER SCHNEIDER: That is, do we need to demand even more than we do that competitive processes be used to acquire long term firm resources?

MR. KAHN: Well, I think Commissioner Beyer can probably better answer that question than I can because he's heard me appeal to this Commission on a regular basis.

But, yes. We would think that would be a direction that would ultimately benefit the ratepayers.

COMMISSIONER SCHNEIDER: Thanks.

COMMISSIONER KELLY: Thank you.

Our next speaker is Greg Patterson. He is the director of the Arizona Competitive Power Alliance.

MR. PATTERSON: Thank you.

I'm Greg Patterson, director of the Arizona Competitive Power Alliance. We like to call ourselves the Arizona Competitive Power Alliance.

(Laughter.)

MR. PATTERSON: I'd like to step back a second and talk a little bit about the bigger picture. John did an excellent job of talking about the details of minute-by-minute, hour by hour economic dispatch. And I think that

Dick did a great job of what happens in the rural area.

Going back to Commissioner -- to Tom's suggestion earlier, was the bigger picture of how you can solve this problem is not done, I think, hourly or daily. I think it's a fundamental policy question of what can be done.

And going back to Commissioner Hinckley's points earlier about what has changed from the '90s, you know, sometimes if you want to figure out where you're going you need to figure out where you are. And to figure out where you are you have to figure out where you have been.

And we haven't come here in a vacuum. We weren't transported to this spot. There was history of this industry and changes that have occurred in this industry both politically, physically and economically that have put us where we are. And sometimes we have to step back and see exactly what happened there to see where we can go in the future.

And I think most of you know that some time in the mid- to late-'90s there was this phenomenon of independent power and the theory that simply having an IRP process that can take several years in which a utility built a power plant and the Commission sent in its auditors to determine if that was prudent, it was put in rate base, and then that was gradually amortized over 30 years and consumers paid for all that, that model came into question during the late '90s on the thought that the independent power producers could potentially produce power on a wholesale market. They could do it more efficiently. And then rate-payers, customers would not necessarily be responsible for stranded investment that was built and yet not economic but happened to be in rate base. And so that was the theory at the time.

And the question became how do we make sure that the incumbent providers, the current vertically integrated utility will dispatch power that's not their own. And we've talked about cost based analysis. And I really appreciate Marcie Edwards' comments because the level of complexity of determining the costs of this system would take the entire Soviet agriculture department to figure out. You can only do so many five-year plans and so many analyses to see who's more efficient by adding up all the costs and seeing where you dispatch.

Ultimately you've got to go the other way, and you've got to bid. Because you don't know what everybody's underlying fuel cost is. You don't know what their alternatives are. You don't know what they're planning. But they do, and ultimately they will bid.

And I think that that became recognized in the late '90s. California certainly looked at that and decided they needed a bid-based system. Arizona needed a bid-based system. The problem, however, is that we can't just suddenly get to a system where we have an entire portfolio of power plants and we have people who need power because we had a vertically integrated market at the time. So you have affiliates involved in the bids. And the solution to that, of not making sure the affiliates just somehow managed to pick their own assets, was to try to come up with some sort of independent monitor system.

But as much as we like to say that electrons are homogeneous, power plants are not. And so you can always craft an RFP that looks fair to the independent monitor and the only person who can win it is the incumbent. Now that can be through credit, that can be through insertion or injection points, that can be through delivery, that can be through a variety of things. But the bottom line is you can't come up with a system in which the incumbent bids for his own plants versus the other plants where it's essentially going to be fair.

And even if it was fair, you've got a problem in that consumers are currently paying for the capacity of those plants in rate base. So either consumers pay twice or you have to establish a competitive bid system in which the merchant IPP plant can bid low enough that they can actually take a full in cost of their plant, cover their fixed costs, and compete with the variable cost of the incumbent's portfolio.

It goes back to Mr. Spitzer's question about what we can do with a new and efficient plant versus a fully depreciated older plant.

California had a solution if we're going to have some sort of forced divesture, we're going to have bidding markets, et cetera. And I think we found out what happens if you have a system that's built over 100 years by electrical engineers and is redesigned over two years by economists. And problems ensued.

Arizona had a similar system in that it needed to be bid-based. But Arizona needed to change it a little bit. Arizona in 1999 entered into settlements with Arizona Public Service, which is certainly the big dog in Arizona, in which Arizona Public Service was going to become a wires company.

Now they did not have a forced divestiture of their generation. For one thing selling a nuclear power plant is not that easy; it takes a long time. And, two, the Commission in its wisdom decided that they would actually establish a competitive affiliate for Arizona Public Service. They could move their power into there and then they would have basically bidding that was similar to the stacking order or the merit order that they would do normally when they wanted to achieve their portfolio needs. None of this hour on/hour off, ten minutes, whatever. You would have your base load with long term contracts. Your shoulders with fairly intermediate contracts. And then peaking would be done on more of an hourly basis. Exactly how you would procure power on your own.

The market responded to that in 1999. Arizona has a favorable tax climate. We have a high growth area. We're close, certainly from a transmission point of view, to Las Vegas, which is a very high growth area. And so in Arizona we had -- Pandeteco came in with a 2000 megawatt plant. Sempra around the Palo Verde hub built a 1250 megawatt plant. Duke built the Arlington facility, 400 megawatts. PPL built the Sundance facility, 400 megawatts. PPL and Duke joined for the Griffith plant, 500 megawatts. Reliant built Desert Basin, 500 megawatts. And PG&E National Energy Group built 1,000 megawatts. In addition to that Arizona Public Service built 1700 megawatts of competitive natural gas plants but they did so in their unregulated competitive affiliate.

That is 8000 megawatts in response to the Commission's rules in 1999. That was a very successful program.

The problem, of course, happened in that in 1999 later in that year we saw what happened in there and in 2000 with San Diego prices. Unintended consequence number one: San Diegans were paying a lot of money for their power.

Then we saw eventually the lights go out in California. California has an appointed Commission; Arizona has an elected Commission. And the words 'recall, referendum, impeachment' are all words that are in Arizona's constitution. And so -- there's a technical term for this but our Commissions freaked out I think is the technical term for what happened with that.

(Laughter.)

MR. PATTERSON: So they called into question what that economic model was after looking at California. But fortunately we were two years behind California at the time and they had an opportunity to rethink it. And in doing so they came up with what they called Track A and Tack B.

And Track A was to say let's look at the threshold issues; let's look at the fundamentals. Do we want Arizona Public Service to divest all of its assets to a competitive affiliate and then bid into a market. Do we want 100 percent of our 6000 megawatts that APS is going to need to be competitively bid, or do we want to come up with a different solution.

Ultimately they solved Track A by deciding that, no, APS could not transfer its assets and that any bidding that would be done would only be the traditional -- excuse me, the base load plants that they had -- the nuclear plants, the coal plants -- would remain in rate base and any bidding would be the increment on that.

Now that changed the rules dramatically. I'm not a lawyer but I would like to be a lawyer. So I try to learn one legal term a year and at the end of 1000 years I'm going to take the bar.

(Laughter.)

And 2002's phrase was 'detrimental reliance.' And that's what happens when someone decides they're going to establish rules and everybody else spends basically five billion dollars in compliance with those rules and then something happens and the people who made those rules decide they would like to change them.

So people were somewhat unhappy with the changes that occurred in the '99-2000 area.

Well, Track B was the implementation of these rules. And so Track B was to bid the 2000 megawatts that was not APS's own existing coal and nuclear plants. So we put 2000 megawatts on the market. APS had 1700 megawatts in the competition to compete with. My clients had about 6000 megawatts in the competition to compete with. We had an independent monitor. APS had to bid first and had to seal it; nobody got to see it. And lo and behold, when we opened up all the bids APS won all of them.

Now we found out how they did it. And it was tricky. They did it the old fashioned way: they bid really low.

(Laughter.)

MR. PATTERSON: And, frankly, you can't complain a lot about that. In fact, Track B since APS's assets won Track B, we could do an interesting analysis. And that is what would it have cost to have APS's assets provide this power under a traditional model of rate-basing the assets versus these bids, which are from the same company and the same assets. The different was $140 million. It was a tremendous amount of money that flowed through to consumers: $140 million by establishing a Track B bidding process and that money flowed back to consumers.

That is economic dispatch. That is where you really manage to get savings. And that is how you flow them to consumers.

Now at the end of that the Commissioners were happy, the consumers were happy. APS was a wreck. And we were having problems too. And the reason is that APS had built 1700 megawatts of what had been described as merchant power. They always said that it was for their own existing customers. But from the looks of it it was certainly stand-alone generation without contracts. And Wall Street at the time wasn't financing that. Now they had bridge loans for that. There was no way they were going to get those bridge loans renewed with long term financing.

APS was kind of stuck. They had originally relied on the fact that the Commission was going to let them transfer their entire portfolio. We were kind of stuck because we had built 8000 or 6000 megawatts of generation and we thought we had 6000 megawatts to bid but we were stuck with 2000 megawatts to bid and APS had won all of it. So we needed a more comprehensive solution.

APS filed a rate case and the members of the Arizona Competitive Power Alliance worked with the Commission staff and actually came up with a settlement for our piece of that rate case. And that is we would let Arizona Public Service rate base those plants, 1700 megawatts go into rate base at a reduced cost to reflect the $140 million of Track B contracts.

In exchange for that our Commission said, 'Look, never again -- or at least not for a while. We bailed you out once. But at the moment you've got 6000 megawatts of merchant power here and we're going to have a self-built moratorium until 2015. You guys have your own plants, you have them in rate base. But the rest of it is going to be bid.'

We had a 1000 megawatt RFP in 2005 which we're finishing now. And the Arizona Public Service territory grows at about 350 megawatts a year. And that, of course, is exponential.

So the theory is that APS is going to have to buy 4000 megawatts on the open market through some sort of long term contracts. They don't have to buy the plant; they don't have to buy it from our customers. They can buy it from anybody who can get power to the Palo Verde hub, which is one of the most liquid hubs in the west, and in doing so they flow the cost of that power through to consumers through a purchase supply or a power supply adjuster mechanism that the Commission monitors very carefully.

So at the end of that cost based bidding -- not cost based top down management -- means that the members of the Arizona Competitive Power Alliance have the ability to try to bid into that system. APS doesn't have an affiliate in those bids any more so we don't have to worry about the bids being done unfairly. And the Commission, Mark Spitzer being the one who gets to run that, gets an opportunity to audit the PSA with such a level of intensity that all of the lower costs of the bids flow directly through to consumers.

So that is economic dispatch on a long term level. And that's economic dispatch that I think is effective. I think it's also a solution that independent power producers and the incumbent utility can work out because, as you've seen through some of the tension here, there is not going to be a solution if the incumbent, through its affiliate or through its own portfolio, is going to claim it's doing economic dispatch and is going to choose what assets in the portfolio get dispatched because the portfolio that they happen to own certainly looks to be the one that's more secure at the time if they do that.

So this is a really good long term solution.

Arizona is a market in which the IPP community is happy and the incumbent investor-owned utility is happy.

COMMISSIONER KELLY: Thank you, Greg. It's nice to end our presentation with everyone happy.

(Laughter.)

MR. PATTERSON: I would like to now sing Bobby McFerrin's song--

COMMISSIONER KELLY: Except Mark has a question.

COMMISSIONER SPITZER: I would say I'm unhappy -- just to correct the record. The use of the term 'recall' -- you're now in California and it's a dangerous term to use over there.

(Laughter.)

COMMISSIONER SPITZER: And I would agree that the state by state method -- and this is in deference to all my state Commission colleagues -- particularly with the retail relationship, is one where the broad public policy ought to be determined at the state level.

And the final correction -- and it's a trivial one -- but I don't think I freaked out.

(Laughter.)

COMMISSIONER SPITZER: And I guess that's -- the Commission -- that's why Mr. Patterson was in the House in those days and I was in the Senate.

(Laughter.)

COMMISSIONER KELLY: Any questions for Greg?

(No response.)

COMMISSIONER KELLY: Thank you.

And I'd like to again thank all of our panelists for taking your Sunday, having to come to Palm Springs and speak to us. It's been quite valuable.

We're going to take a fifteen minute break. And then we'll have a discussion about where to do from here.

The panelists are invited to come back for the discussions if you have time.

Thank you.

(Recess.)

COMMISSIONER KELLY: Would the Joint Board Members please take their seats.

The next part of the meeting is devoted to the panel members. So I'd like to open the mic and open the mic to you first for your comments, your thoughts on what we've heard today, your thoughts on the next step that this Board takes.

Ric.

CHAIRMAN CAMPBELL: Let me offer just a -- This is Ric Campbell.

Let me offer just a few observations and thoughts that I had as I listened to the panelists. And one is is that often times we as a region say we're quite different than the east and we need to be treated differently. And as I listened to the discussion today I think we could say the same thing within our region.

I don't want to necessarily boil this down to a retail choice state versus non-retail choice state. But it seems to me that there are differences and that while there might be some interconnection-wide ideas that would benefit everyone that could be explored, that there seems to be a difference of opinion as it relates to whether you have a bid-based system or whether you use a vertically integrated system where they perform their dispatch through merit.

So I guess my first word of caution would be is that we not look at this as just one size fits all, that there is a list of five ideas that we're going to slap across the whole region; that we might want to make distinctions between the ways different states operate.

And I would like to, though, explore also some of the ideas as far as -- there was one idea from the California ISO about something WEC could do. And I'd be interested if there's anyone from WEC that understands that issue whether they'd be opposed to that idea of when they do their hourly scheduling that they don't do that just on the hour but they do it throughout the hour. I'd be curious if there's any opposition to that idea and what it is and why.

COMMISSIONER KELLY: Thanks, Ric.

Rolayne.

MS. WIEST: Thank you. This is Rolayne Weist from the South Dakota PUC.

And since South Dakota is also heavily involved in the MISL region I think that one of the things that we would caution the Joint Board to really think about are the costs associated with such an organization.

I think that a number of our utilities have been surprised by the costs and are increasingly concerned about those costs.

Thank you.

COMMISSIONER KELLY: Thank you.

Dian.

COMMISSIONER GRUENEICH: I stepped out for a minute. Are we just going around the room and giving our thoughts?

COMMISSIONER KELLY: Yes.

COMMISSIONER GRUENEICH: It seems to me that -- I'll put on my hat looking at how this report may address specifically the California ISO issue.

And I think that Marcie had raised some important issues of looking at what's the level of complexity that's involved when you are getting into the economic dispatch using the bid system, and basically at what point do you stop because the benefits that you're getting are not offset -- or the costs that you're imposing on the participants are not offset by the benefits that you're getting, that I was particularly taken with some of her remarks about for smaller participants when you are refining a system essentially to squeeze out the most in terms of economic benefit you may have a situation where the real life impact is to discourage participants from interacting in that system.

And I think that that's a very real life concern that I'd like to make sure that the report addresses, that we're not just so far into the ideal of economics that we forget that these are people who are at least in California joining the ISO on a voluntary basis. And there has to be a reason why they think it's going to be improving their life.

And then the second aspect which we had discussed at the beginning was again in California where we have a whole host of non-economic aspects or at least costs that may not be internalized that are obviously very important to us where we view that -- certainly reliability and economics is central but we also have our RPS, we also have our air quality considerations. And again I think it's very important that the report acknowledge these factors as well.

COMMISSIONER KELLY: Thanks, Dian.

Greg.

CHAIRMAN SOPKIN: Thank you.

In trying to figure out what security constrained economic dispatch means I'm still a little uncertain as to what the word 'security' means in that term. And I'm not sure if we can get an answer here.

I guess my concern about this entire process is it may have an over-reliance on the transmission aspect. And we need to look at generation as well. And I'll give you an example:

Our local vertically integrated utility is having an RFP as we speak. And one of the proposals is a mine-mouth coal plant in Wyoming with probably a 200-mile transmission line. And that's going to be competing against, you know, a local combined cycle plant, for example, looking at the higher natural gas costs. And it just seems to me if we're just looking at transmission that that ignores another way to achieve economic dispatch, which is generation.

And what worries me about this whole process is I keep thinking what is broken with our -- we call it LCP, least cost planning process, and what is the end game of this process.

COMMISSIONER KELLY: Thank you.

Lee.

CHAIRMAN BEYER: I guess a couple of things come to mind. One is just the whole definition about what piece of the action we're talking about in terms of the schedule. Are we talking about the full schedule, day ahead schedule, or are we just talking about the real time balancing schedule. I mean the latter makes more sense to me rather than the former.

That sort of gets to some of who's going to be responsible in the end for being accountable to the rate-payers, realistically. Is it going to be a federal or state regulator or is it really going to be the load-serving entity.

The other thing is I think the definition of economic. I mean what is that. I mean I think there is an implied definition. We think if, well, obviously it's the cheapest units to run. But it's not necessarily so.

I think what we're really looking for from a ratepayer standard is what's going to be the cheapest return for the ratepayer. And just choosing the most inexpensive or most efficient generator doesn't necessarily mean it's the lowest cost to the customer in the end because, as I think Greg was talking about, we still have included a lot of generation capacity in rate base already. So are you duplicating that.

And the other point, I was just thinking a lot about what -- I guess she's not here -- Marcie Edwards said. At least with respect to for-profit IOU companies the issue that's there, just because you get a cheaper buy doesn't mean that it passes through to the customer. It may just mean you got a better deal for the shareholders. And so I'm not sure that's a major improvement.

And I guess my last point is it just seems -- just sitting here listening it strikes me as very, very difficult for us in the regulatory framework, either at the federal or the state level, to duplicate on a very complex issue that utilities are dealing with every day -- and in fact every hour.

COMMISSIONER KELLY: Thanks, Lee.

COMMISSIONER SCHNEIDER: Tom Schneider, Montana.

I recognize that the legislation was passed and that's a political and legal reality. But from my perspective it's misplaced in terms of priorities. Economic dispatch is but one component of bigger issues related to resource adequacy, constraints, infrastructure development, non-wire solutions, demand response. It really -- that is the integrated goal that we've had in our individual load serving entity plants, whether they're IRP or least-cost planning or default supply planning. And the emphasis on economic dispatch just seems to short-term and it's like the tail wagging the dog.

I know we need to respond to Congress. And I know that -- and I actually think the vehicle of the Joint Board and the vehicle you've set up here in terms of input is a valuable one because it is so multi-dimensional, even economic dispatch in a hydro system in the west, you've heard lots of the public policy tradeoffs between fish and transportation on the Columbia River system, for example.

So I don't know what my bottom line is other than we need to draw that very clear distinction in terms of relative importance of economic dispatch. For example -- I'll be more specific:

The Grid West footprint, which is a substantial regional footprint -- at least the concept -- economic dispatch was a -- I wouldn't say minor, but only a moderate cost-benefit portion. The longer-term planning, the resource adequacy, the infrastructure, the non-wire solution, all of those things and the independent operations were probably swamped or dwarfed the economic dispatch portion of it.

So basically in response to the independent power producers, they're not going to finance plants on economic dispatch hour to hour. They need long term contracts and the financial stability that that reflects in order to develop these facilities.

It's only the existing facilities that economic dispatch really ends up being the driver. So somehow we have to carve out a report to Congress that's responsive but yet tries to put this thing in perspective. Yes, there is some economic value to better regional broader dispatch. But we've got a hell of a lot more important issues than that.

COMMISSIONER KELLY: Thanks, Tom.

Mark.

COMMISSIONER SPITZER: Thank you.

Mark Spitzer again from Arizona.

I guess the lawyer in me looks at applying the facts of a particular case to the controlling law and then deliberating as to a result. And the testimony suggesting differences is -- again suggests there's trouble in reaching a uniform solution.

I must admit I was disturb by some of the testimony that we've gone retrograde since the 1990s in terms of applying economic dispatch that I don't think was the circumstance in Arizona. But the fact that it occurs within the interconnections is troubling.

Those layers of complexity -- and I would agree with Dian: environmental impacts are serious and need to be taken into account. And they are somewhat idiosyncratic.

When I was in the legislature we negotiated a state implementation program because most of the state was in a nonattainment area. And so this was worked out with the Region 9 EPA Administrator and then we went back to the legislation and embraced all of the utilities. All of the generating utilities in Arizona participated in the legislation and in settlement.

And those are externalities that I think definitely enter into security constrained economic dispatch. And again, because they're idiosyncratic, are difficult to apply on a uniform pattern.

From the big picture point of view the sword of Damocles hanging over our heads in Arizona is natural gas. And I would applaud the efforts of Congress and of the FERC in working on infrastructure that's desperately needed, in terms of storage, pipeline capacity, LNG terminals and the like, because that increased infrastructure capacity gives fruit to the combined cycle model. And if we don't solve the natural gas crisis that that model disappears and leads to certain problems in terms of creating the generating capacity that we need.

But I think overall I would like to see a response to the Congress -- that's obviously mandated -- that provides some general guidelines and incorporates general discussion. But again I would agree with Ric that a uniform approach, given the varied circumstances of the competing service territories, is problematic.

COMMISSIONER KELLY: Shirley.

COMMISSIONER BACA: I think when I first read the definition of 'economic dispatch' and looked at it as economic dispatch versus efficient dispatch it gave me the immediate feeling that there was a presupposition that the states and/or the regions did not already have economic -- were not practicing economic dispatch practices. And, you know, as they say sometimes in Texas: if it ain't broke don't fix it. And it doesn't mean that there doesn't -- that we don't have room for improvement and that we couldn't talk about different considerations for improvement.

But it appears to me that already a lot of the practices that are occurring are those practices that do in fact have the utilities practicing as much of an economic dispatch practice as is best utilized for their own area or, if it's in the case of a region or an alliance for that area.

I don't think that efficient dispatch is equated with uneconomic dispatch. And I think that when we look at things -- we have to look at all the different kinds of components, including -- well, I heard several things today. If you're looking at, you know, short-term fuel costs, fixed capital costs, emission rate, plant location, interconnection with the grid, thermal efficiencies, et cetera. So I just don't think that it's a one size fits all approach.

Certainly I think that from what we're doing in New Mexico and our major providers, Public Service Company of New Mexico and El Paso Electric Company, if we're looking at institutional, regulatory and statutory impediments you're looking at building transmission lines or building a generating plant that perhaps would require a multitude or multiple regulatory proceedings for the CCM approvals for siting and what have you. And I think that that could become a lot more complex and a lot more cumbersome than what we're already doing. And I'm not sure that that would be something that would be in the best interests of the provider.

The other thing was when you look at the EEI testimony before Congress I think one of the things that they talked about -- because one of your questions is 'Are there institutional, regulatory, or statutory impediments.' One of the things that they said that might be something you'd want to look into is that in addition power plants could take new steps to increase their efficiencies if EPA's 2003 NSRO were codified and increased inefficiencies at existing plants leads to lower fuel consumptions or whatever, and because of the electric power industry's emissions of SO2s, NOX are capped and the regulations require state of the art emission controls for all new plants, such improved NSR policies would not increase the emissions.

So I think that's one of the other things this codification of some of the existing rules that have been imposed and whatever.

So I think if we look at some of those areas where we might be able to deal with specific issues, regulatory rules or NSR rules, FERC rules, maybe that might be another approach. But to redo it to me would kind of go backwards in time, too. And so for sure for New Mexico, I think, let's just look at those areas that we might be able to work on. But certainly don't put everybody into the same -- you know the west and west connect certainly have their own independent approaches and likes to keep a lot of that independence as we're looking at some of these economic dispatching practices.

COMMISSIONER KELLY: Thank you, Shirley.

Mark.

CHAIRMAN SIDRAN: Mark Sidran, Washington State.

I'm sure you are shocked to hear a state regulator suggest that these are issues best left to the states to deal with. But it does seem to me that historically, at any rate, power supply issues have been largely the responsibility and the purview of the states and their Commissions. And I'm not -- to echo a point that Ric Campbell made at the very beginning, whatever the intent was that Congress had in mind, I hope that the way that FERC -- and again I applaud, as others have, the convening of Joint Boards -- but I hope that FERC will point out to Congress the substances -- I'm sure FERC will -- of the comments that have been made here today, which I won't bother to repeat.

But what I haven't heard today has been a compelling argument for either legislation from Congress or for that matter some kind of regulatory response from FERC under its existing powers. And it does seem to me that the burden lies on those who think that something needs to be done by way of Congressional action to be fairly specific in identifying what problem exists that legislation would remedy.

That's not to say that there aren't opportunities for improvement and there were several comments today that suggested there were opportunities for improvement. But I also didn't hear anyone say that those opportunities could not be taken advantage of by states individually or, as we do here in the west, working collaboratively within our existing institutional structures.

COMMISSIONER KELLY: Thank you, Mark.

Any more -- Richard? I didn't want to leave you out if you have comments.

MR. HINCKLEY: I certainly don't disagree with any of the sentiments that have been expressed. I'm concerned, as I'm sure you all are, with the questions that I think kind of begs, which is what enhancements can be effectuated in this very diverse scenario to hopefully bring some impacts.

I'm not sure that I heard too many suggestions as to what those potential enhancements are today. I think it will be worthy of our further effort to try and identify some.

It's interesting to me that whether we look at the issue of whether a centralized management, independent management of some sort or another will facilitate a more economic dispatch, I didn't know that Grid West or any other independent organization was really taking on that much activity in contrast to just trying to make more accessible, easily, most cost efficiently, hopefully, transmission, which would then have as a byproduct a more, again, robust wholesale market, and without management per se let the market allow for efficiencies and so forth.

In terms of what improvements can be considered, I guess that issue still eludes us somewhat. But I think if anything a report that would try and identify either their non-existence or try to identify just what things might start to make sense to consider and think about considering the different characteristics that have been mentioned here, that would seem to me to be an element of the report that would be helpful.

And I think it would be helpful to FERC as then it takes on its responsibility to submit the report to Congress with some meaningful elements and have it received in such a way that the Joint Board work is appreciated and understood to, you know, have been difficult because of the situation but yet still bringing forth some elements that I think might be viewed as truly things that can be studied for their benefit and see if there are on a regional basis improvements or enhancements to the individual activities for the benefit of the western states.

COMMISSIONER KELLY: Thank you.

Cindy.

DEPUTY CHAIR LEWIS: Everybody has been so eloquent. I'm sitting here trying to think what I might be able to actually contribute.

It strikes me that the report requested is information-gathering. And a lot of the comments that we have presume that by providing this report that somehow we're conceding that somebody else or some other entity or federal law should emanate that would take the dispatch from the areas where it's currently being done. And I guess my thinking is that maybe that's not the direction it's going; maybe it's truly information gathering to determine if something further is required.

And one thing that -- a comment somebody made -- I think it might have been Ms. Edwards -- struck me. That it would be really important in any report that we make that we define the terms that we're talking about very clearly so everybody's on the same page. And maybe our suggestions are not going to be economic dispatch on a west-wide basis. But with our terms defined so we're talking about the same thing within each control area maybe our description would be, and maybe those are the conclusions we reached, that it is best controlled on a control-area wide or a much smaller subregion-wide basis. But we're talking apples to apples and oranges to oranges.

So I guess that would be my concern as a starting point for the report. What are we actually talking about.

COMMISSIONER KELLY: Thanks, Cindy.

Barry, thank you for joining us. I know you ran into a massive airline delays. I appreciate your soldiering on and joining us.

You didn't hear most of the panelists earlier. However, you come from a state that's pretty unique -- Texas -- in many ways.

COMMISSIONER SMITHERMAN: Indeed.

(Laughter.)

COMMISSIONER KELLY: But certainly in the organization of your dispatch. And you -- It's unique in that ERCOT is within Texas and all of the resources are within Texas and they're all under Texas jurisdiction.

So to the extent you have any comments for us about Texas's experience or how you think this report should proceed, it would be great to hear from you.

COMMISSIONER SMITHERMAN: Well, thank you very much.

And I apologize for being late. I spent a lovely three hours in Sky Harbor Airport this afternoon. And I look very much forward to being back here right after the first of the year as the University of Texas plays a local team --

(Laughter.)

COMMISSIONER SMITHERMAN: -- hopefully for the national championship.

You know, we are so unique from every other part of the country that I think what would be most helpful perhaps -- and I'd be more than happy to visit with anyone -- what are the things that we are continuing to try to improve as we migrate our market from a market that has five zones presently to one that will have a nodal market design, from what has always been understood as an energy-only market to a more formalized energy-only market. What are the lessons that we've learned through our experiment in economic dispatch.

And I would just say there have been a couple of resounding benefits, all of which relate to the more efficient use of natural gas.

Between 1999 and 2003 about 26 gigawatts of very efficient natural gas generation was put in ERCOT not in rate base. And the result of that has been a dramatic mothballing and retiring of old inefficient gas plants, about 7000 megawatts to date have been mothballed or retired. By one study we've seen a dramatic increase in electric generation from natural gas, but only a minimal increase in the consumption of natural gas. So I think that that is a good testament.

And we've also had a very dramatic reduction of NOX and SO2, particularly in the nonattainment areas of Dallas, Fort Worth and Houston.

Having said that, we've still got a lot of things to work on. And we need to work on bringing our intervals down from fifteen to ten or to smaller increments so that the ISO can manage dispatch more efficiently. We need to do some work on getting real ramp rates for our generators rather than estimated rates because right now we've got a schedule control error that's too big.

And so there's debate between generators and ERCOT operations about what the real numbers ought to be. But it has a price tag associated with it. We need to get QSCs to stop relying on the balancing energy market because it's more volatile and to enter into bilateral contracts which are less volatile.

And I think we need to recognize -- and a couple of people said this indirectly -- that the more we move to efficient dispatch the skinnier our reserve margins are going to be. And so as a result we have to get comfortable with those concepts. And that brings us into the whole conversation about energy only versus capacity which we have, at least for the time being, resolved.

So anyway, I'll stop there. I'll be here for a couple of days. I could talk for a long time about the uniqueness of our market. But I'd be more than happy to visit with anybody in person about what we think we've done right, what we've done wrong, and where we hope to improve.

COMMISSIONER KELLY: Thank you, Barry. Appreciate that.

Okay. Well, I'm going to take a stab at what I think I've heard and put it into a framework for our next steps. So let me propose what I think I've heard.

As we progress to the next steps of writing the report I've heard clearly that when we talk about the state of economic dispatch in the western region we have to be very careful that we explain how different it is from subregion to subregion. I think I've heard that pretty clearly.

That when we talk about the strengths and weaknesses of economic dispatch we have to be clear that there are other goals in our dispatch in most areas. Efficient use of our hydro resources, environmental concerns, renewable portfolio standards, of course reliability, to name a few, and that we should describe that.

I've also heard that no one sees a -- Well, I haven't heard anyone say we should be involved in a big overhaul of how we do things and that we certainly don't want to propose something like that to Congress. Nevertheless I have heard from most everyone that we should look at ways where we can improve things, opportunities for improvement, enhancements that might be effectuated. That we should try to identify what could be considered, including, to the extent we can't identify things, explaining that.

And then perhaps explaining the barriers to those improvements or the complexity -- I've heard that a number of times -- the complexity involved in making changes.

So I would at this point see that that's what our report is shaping up to be, that kind of a description: the state of economic dispatch in all its differences; the strengths and weaknesses of it; and the improvements or enhancements that could be considered and the pros and cons of those.

I think that we will have some more input. Certainly DOE will soon finish its study. And I suspect that we'll find a lot of information there that we may want to acknowledge or incorporate by reference or perhaps just refer to.

I'd like to leave our record open to the public and we'll put a notice out that it is open to the public so that all interested parties can submit more information that would help us in our effort.

And so I would see that the next step would be to draft this report and bring it back to the panel or bring a draft back to the board, the Joint Board. I would suggest that perhaps we do that at the next NARUC meeting in -- February? -- and hopefully we'd have a draft available before that and we could circulate it. And then we could determine before that meeting in February whether we needed another public forum, whether we needed more input. And as we got closer to February we could probably have a better understanding of where our gaps are, what additional knowledge we might need.

February 12 to 15 in D.C. is our next meeting.

So that's what I think I've heard. But I'd like your reaction to that: Yes, no?

Marsha? Thoughts?

COMMISSIONER SMITH: I think it's a great idea.

(Laughter.)

COMMISSIONER KELLY: I told her to say that.

COMMISSIONER SMITH: No. It's just that I don't know how much longer I can sit under this cold air.

(Laughter.)

COMMISSIONER SMITH: Anything to get to the sun.

COMMISSIONER KELLY: One reason to move on.

Any thoughts? Violent disagreements?

COMMISSIONER SMITH: Actually, I think that is responsive to Congress. I think we do need to be attentive, as Commissioner Schneider said, that it is the law, it's reality. And we need to be responsive to Congress in a responsible fashion.

I guess the other thing that caught my attention was Commissioner Beyer's comments and maybe Marcie Edwards, which reminded me that -- I try never to talk about least cost without talking about least risk, because unless you consider the two together you may end up with something that you thought was least cost but because of the risk it turned out not to be. So it's least cost/least risk from my point of view.

But I think as far as getting the report, having the opportunity to accept further public comment, having the opportunity for all of us to review the report and comment on it and then meet another time to finalize it, to see if we can figure out what -- if there are items to suggest for improvements or avenues of progress we could make on this issue. I agree with Tom that it's not the top of our list, but certainly it's nothing that we want to have slide through the cracks and forget about. So we need to keep it on our radar screen along with all those other important topics.

COMMISSIONER KELLY: Tom.

COMMISSIONER SCHNEIDER: Commissioner, I just would say there has been a lot of work done on a regional basis, west interconnect basis, about the component of economic dispatch. And it seems to me in terms of the quantification or at least the range and the band that have been used in cost-benefit analysis, that those ought to be incorporated. That is, this is the best analytical work that's been done. It's not perfect. But you've got the Grid West work. Undoubtedly there's west connect work. And I don't know, where California is.

But that would at least put some order of magnitude to things. And I think that particularly being more familiar with the Grid West, it gives you an idea of the relative magnitude of economic dispatch benefits versus other economic benefits that we're looking toward in terms of an independent transmission provider.

COMMISSIONER KELLY: Thanks, Tom. That's a great observation.

Sarah McKinley, who has been in the south meeting where Chairman Kelleher and Chairman Callahan are holding -- are chairing the meeting, has told me that the decision there was to leave the record open for additional comments until December 5th. How does that sound to you? Okay?

(No response.)

COMMISSIONER KELLY: We'll do the same thing, Sarah. You can tell the Chairman we're following his lead.

We actually have four minutes. And since our mics are open, if there's anyone in the audience who would like to say anything for the record at this time -- Sure, come on up.

MS. PHILLIPS: I'm Marcie Phillips from Constellation.

COMMISSIONER KELLY: Marcie, would you use that microphone?

MS. PHILLIPS: Sure.

And I can't help resist saying you have policy choices which are yours to make. But I did hear quite a few misstatements and misconceptions about economic dispatch that I think for the record you ought to at least work on a clean slate and then decide as a societal value whether it's important to you and whether there are benefits.

First, it is technologically possible. You can tell what the costs are. But you are absolutely right to be concerned about the cost of implementing it because, unfortunately, ever ISO that you see or person -- entity that uses it today has used their own technology information. And that's what costs a lot of us a lot of money.

So I would suggest if you do go down the road of implementing economic dispatch you use available technology because that will save you a lot of costs.

But I'm sorry, I must disagree with Ms. Edwards. You can tell who is going to benefit. And it doesn't have to be a have or have-not option when it's all done. That's up to you to decide whether you want to have cost causation, whether you want folks that are in higher cost areas to pay for it or not. But it doesn't have to be done that way. You can have a single clearing price where you dispatch the system and everybody pays the same thing. And you don't create have or have-nots; you've simply run the system at cheaper cost by dispatching the most efficient unit.

I also have to dispel any myth about reliability. Economic dispatch anywhere where it's done throughout the country is never sacrificed for reliability. And so that is a non-issue.

You always run the unit that's going to keep the system working. It doesn't matter what it costs. So I think when you're in your deliberation it's really a red herring when you throw that out. That's a code word for saying 'I really don't want to do it' because nobody doubts that reliability is primary over everything.

And finally, I just have to address this idea that it's the shareholders that benefit. It's up to you -- all of you have the tools, all of you regulators sitting around here have the tools to make sure that your retail consumers get the benefits of wholesale competition. And the fact that you run a cheaper unit and the wholesale price goes down, that's up to you to translate it. The fact that somebody's shareholders get some money because their unit ran is irrelevant to the fact that you have caused the overall wholesale market price to go down. And that's up to you to translate that however you want into consumer savings.

So you have lots of policy choices. But I wanted to dispel some of the rumors about what economic dispatch does and doesn't do.

Thanks.

COMMISSIONER KELLY: Thanks, Marcie.

Leon.

MR. LOWERY: There have been a number of questions about what Congress wanted to know. And as the staffer for Senator Bingaman who is to a great extent possible for the economic dispatch provisions being in the bill, I thought I might take a whack at that.

COMMISSIONER KELLY: Thank you.

MR. LOWERY: It's about one thing: natural gas prices. When natural prices are so shockingly high right now and forecast to be very, very high for a very, very long time, for the foreseeable future, the question that comes to Senator Bingaman when he hears that some less efficient plants are being dispatched while more efficient plants are sitting idle is why is that; are there opportunities to dispatch the more efficient plants to save -- to reduce the demand on natural gas. Are there enough opportunities that it's worth it, taking into account all the constraints for transmission, for reliability, all of those other things.

And these are questions of fact. Are there enough opportunities to, by changing the way plants are dispatched, save enough natural gas that you affect the price of natural gas. And that's why Senator Bingaman is supporting looking at this question -- and not just economic dispatch but even to the extent of thinking of looking at efficient dispatch.

So that's what he was up to by asking for these studies. So, you know, as this goes forward keep that in mind: It's about the price of natural gas.

COMMISSIONER KELLY: Thanks, Leon.

Any more?

(No response.)

COMMISSIONER KELLY: Well, we are finishing on time. But I want to thank our panelists and the board members for participating today.

But the board members, we need to convene at the head of the table here for a picture.

(Laughter.)

Thank you very much.

(Whereupon, at 5:00 p.m., the proceedings in the above-entitled matter were adjourned.)