BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CALIFORNIA TECHNICAL CONFERENCE :

ON WHOLESALE POWER MARKET DESIGN :

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California Public Utilities Commission

505 Van Ness Avenue

San Francisco, California

Thursday, November 6, 2003

The above-entitled matter came on for technical conference, pursuant to notice, at 10:15 a.m.

APPEARANCES:

COMMISSIONERS:

PAT WOOD, III, CHAIRMAN PRESIDING

WILLIAM L. MASSEY

NORA MEAD BROWNELL

APPEARANCES CONTINUED:

FERC MODERATORS:

SHELTON CANNON
SUSAN POLLONAIS
DEREK BANDERA
JAMIE SIMLER
DAVID PERLMAN
J.B. SHIPLEY
LEN TAO
CHARLES WHITMORE
CHARLES FAUST
BUD EARLEY
BRIAN LEE
SARA McKINLEY

CALIFORNIA ELECTRICITY OVERSIGHT BOARD:

CHAIRMAN WILLIAM KISSINGER
ERIK SALTMARSH

APPEARANCES:

PRESIDENT MICHAEL PEEVEY, CPUC
COMMISSIONER LORETTA LYNCH, CPUC
COMMISSIONER GEOFFREY BROWN, CPUC
COMMISSIONER SUSAN KENNEDY, CPUC

APPEARANCES CONTINUED:

SEAN GALLAGHER, CPUC

SPENCE GERBER, CISO

P R O C E E D I N G S

(10:11 a.m.)

CHAIRMAN WOOD: Good morning. I'm Pat Wood, Chairman of the Federal Energy Regulatory Commission and, since this is an open meeting of our Commission, I'd like to formally call this meeting of the FERC to order.

I want to, first of all, thank our host, President Peevey of the California Commission, and Commissioners Lynch and Commissioner Kennedy and Commissioner Brown for you-alls hospitality. We appreciate the opportunity to use these nice facilities here at the California Commission.

We'd also like to express our appreciation to the other Commissioners who are here today. We have two members of the California Independent System Operators Board, Michael Peavey, the Chairman of the Board, Michael is here, and so is Mr. --

(Applause.)

VOICE: The new governor has already appointed an additional czar.

(Laughter.)

CHAIRMAN WOOD: I have so many Michael's here.

CHAIRMAN KAHN: Michael Kahn.

CHAIRMAN WOOD: Michael Kahn, President of the Board, is here, and Michael Foria , who is a member of the Board, is also here. I want to thank you all for your work.

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We've also got Eric Saltmarsh, from the California POV representing Chairman Kissinger here today with us up on the stand.

I want to thank the many stakeholders who we'll be talking with through a number of panels today. We appreciate the hard work that you-all have done over the past several years to restore these markets here in California to customer-serving markets.

We are in the process -- this is the ninth of a series of meetings that our Commission has had across the country to meet in the different wholesale power market regions to discuss progress -- or, in some cases, lack thereof -- toward development of wholesale power markets that deliver efficiency and value to customers. And this is actually on, as I said, on my form here, and comes just a few weeks after the Commission, our Commission, issued a guidance order with regard to some significant developments filed by the California Independent System Operators to progress its market to a more complete market design.

This is a perfect time for this meeting. There was a good hydro year here in the West. Markets are not under the kind of stress that we saw. Certainly when Nora and I had our first meeting out here at your sister agency, the California Energy Commission back in 2001, it was a year when markets were under severe stress.

But that should not, I think, cause any of us to relax.  I think, on the contrary, this is a time to act and we can act soberly, look at the issues and values that are important to the California marketplace, and prepare for perhaps a future when we don't have a good hydro year and, after many other units perhaps some of the older, more inefficient, environmentally-challenged units have been retired.

So our focus at our agency, I think much as it is here at the State Commission and it was when Nora and I both served on state commissions, is that our job is to really oversee three things:  balanced rules, in this case rules in the marketplace, sufficient infrastructure, power market infrastructures, and vigilant market oversight.

I think we've made a lot of strides on market oversight, particularly due to the experiences we had as an agency and you-all have had in the marketplace here several years ago. And we have always appreciated the close interaction with the California ISO Market Division and then their Market Oversight Committee, chaired by Dr. Wallach, who enthusiastically two weeks ago approved a balanced proposal that the California ISOs put forth in their MDO2 docket.  This was our first chance to respond to really the final phase, the details of the final phase of the implementation of the new market design for California that we all have been discussing really since 2000, late 2000.

Chairman Peavey, on behalf of the Commission, you wrote a couple days ago a letter to me and to my colleagues about that order and I want to use this opportunity to emphasize that our response to the California ISOs market design filing was our first one. We said yes to quite a few things, but we did not say no to anything, we did not reject proposals of the -- particularly those that were mentioned in the letter. We actually asked for a process to set up so we can better understand those.

And so today is the first step of that process. We have a number of panels planned to discuss various aspects of the wholesale power market out here and we have committed in our ordering -- as I commit to you here today -- to continue that process in a more face-to-face forum.

One of the things we discovered with a pair of orders -- one for this market and one for the midwestern market that we issued two weeks ago -- was that parties get kind of into the litigation practice pretty quick when they file something at FERC. And I think there's probably not been a meeting that I've done at FERC that hasn't gone by that we have not had one or two filings from the California ISO to deal with, you know. I've personally learned from experience. And many of you are getting billable hours in the audience for just --

(Laughter.)

CHAIRMAN WOOD: So enjoy that Lexus when you drive it away.

(Laughter.)

CHAIRMAN WOOD: The focus, though, needs to be on resolving the problems. And I do want to commit, Mr. Chairman, to you and to the market participants here in California, to Chairman Kahn of the Board and the others that we want to work in a more face-to-face and informal format that gets us out of the litigation posture until we're ready to make final decisions.

One of the things we saw in this order were there are some open questions that we want to get understood. We know that the state has a critical role to play in the, I know, the pending procurement decision that is before the Commission here and we want to understand that decision and how it might interplay with the rest of the market design here.

And I think those important pieces, when they're out there, then we could sit down and I think -- with our staffs, with the experts, with the market participants -- talk about how to really wrap up the remaining open issues.

And I do think it actually is a short list; there are some important items on it though -- it's a relatively short list about where it is that the marketplace here in California is going and the role that we can all play together to help provide some leadership within that role. So we look forward today to look at those -- the interplay of those issues and commit that there will be some further work to go on that.

Our hope is that really, as with the Midwest, which is recovering from -- this is relating to the power blackout of theirs that they had in August -- that we look thoughtfully and focus sufficiently on what the market design should be and do that in the spring and then allow then the market participants, under the leadership of the ISO, to really put more focus on the software, on the detail rules, on the training necessary for folks to be successful and to understand fully the market before the market changes are introduced and go forward there. So again it's my hope that we can, from the regulatory side of this, make some decisions that can give the rest of the marketplace sufficient guidance to move forward and then we can, at that point, pursue -- or continue our market oversight.

I do want to just add a couple of final thoughts.

I look forward to a frank exchange today with our panelists.

We've got some members here of our staff, Mr. Cannon from

FERC will be kind of be the facilitator of our panel discussions today. I want to invite my colleagues from FERC and from the CPUC to jump right in with questions and issues. Our staffs here will be asking questions as well as we go through the day of the different panels.

And we're trying to -- I know we've got a lot squeezed into today, but there are a lot of issues here. This is a critical market to, not only the West, but to the whole country. It certainly has been an issue dominating the agenda at FERC since I came in there two years ago with Nora. And I know Bill has got more years on that than probably he wants to talk about as well.

(Laughter.)

Again, our support of the order on the MDO2 two weeks ago was our first response to the final phase of market design; it's not the last. It's my hope that as we go forward FERC will continue the posture we adopted in the other markets that we're going forward of where we need to weigh in formally we will with an order that's interlocutory so that we can continue to have discussions and not worry about ex parte concerns, by continuing to talk face-to-face and allow Commissioners and market participants and staff and everybody to interact.

So this is a little bit different M.O. than we've used in the past. It's one that I have used in my prior position as a chairman of a state commission with some success, so I hope it will work well here in addition.

So again thank you all for coming -- I know there's some folks standing in the back. We appreciate your interest in this real important market. And so without further ado, I'd like to ask if President Peevey has any thoughts.

PRESIDENT PEEVEY: I always have thoughts.

(Laughter.)

PRESIDENT PEEVEY: I also have comments.

First, let me just say to all of you in the room here -- and this is the requirement of the fire marshal -- that as many of you as you possibly can, please take seats because we do have adjoining Conference Room A, where those that tire of standing, I guess, in the back can migrate to and listen to this. It's audio, not video, but we do have that. But it's a requirement of the fire marshal that all the seats be occupied inasmuch as possible here. So I hope you'll take my admonition seriously in that regard.

I do want to welcome to San Francisco Pat Wood and his colleagues, Nora Brownell, and Bill Massey. It's great to have you in San Francisco. And as the Mayor of San Francisco, if he were here, would say Welcome to our house.

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COMMISSIONER BROWNELL: Nice house.

PRESIDENT PEEVEY: Not bad. Not bad, right?

But we're very pleased to have you and your staff here in California today to talk about the important market design issues set forth in today's agenda. I think we all look forward, my colleagues all on my left, look forward to an open and informed discussion. Obviously many people view this meeting as very important, judging by the turnout.

Since becoming President of the PUC in January, I've focused on several goals which I've communicated to audiences inside and outside our Commission. The main theme that I wish to project was to enter an era of partnership. The goal of the partnerships was to increase the effectiveness of the PUC in performing our regulatory duties.

The offer of partnership was extended to my colleagues on the Commission, our staff, parties appearing before us, other state and Federal regulators -- particularly the FERC -- the California ISO and the Cal legislature, as well as local government. My hope in launching this initiative was to exit the energy crisis, including ending the bunker mentality that surrounded the Commission during the energy meltdown here in California.

To this end, we've spent a great deal of effort this year working cooperatively with California ISO to develop a revised market redesign proposal that protected California consumers, promoted efficiency, and provided sufficient opportunities to promote and retain investment.

I want to commend Cal ISO for being responsive to the Commission's concerns in this process and for filing a proposal with FERC that we thought went a long way toward achieving those goals in a responsible manner.

We've also sought to increase and improve our relationship with FERC, both at the Commission level and the Staff level. We anticipate that today's conference will be another major step towards furthering this goal, given the give-and-take here.

I must say, however, that -- thank you, Victor. I must say, however, that the FERCs order last week on the ISOs revised market redesign proposal was disappointing in certain respects from our perspective. The order seemingly rejected the ISOs proposal, which the CPUC strongly supported, on several points that are critical to any implementation of a market redesign in California based on locational marginal pricing, or LMP.

Many parties have substantive concerns about moving to an LMP-based system, concerns driven in part by recollections of the unrestrained exercise of market power during the recent crisis. While I personally believe that the ISO markets require reform and that, if implemented properly, an LMP system can benefit customers, I'm sensitive to such concerns. This is why the CPUC was careful to express conditional -- and I emphasize conditional --

support for the ISOs proposal contingent on the adoption of a large package of necessary features.

One thing that is absolutely clear, for instance, is that any LMP-based system must have effective local market power mitigation. This is simply a function of determining prices at a lower level of granularity, which in most cases there will be fewer competitors and in some cases none.

FERC has recognized this in other ISO markets and has provided to the PJM ISO essentially the same mechanism that the California ISO proposed. Yet, in last week's order, FERC refused to approve the ISOs local -- California ISO's local market power mitigation proposal.

Last week's order also rejected other market design elements that our Commission thought critical to successful prudent implementation of an LMP-based system, including a day-ahead must-offer obligation to prohibit withholding and a proposal to limit nodal prices to $250 a megawatt-hour. As we stated in our comments, these are precisely the kind of design elements that -- quote -- would help to allay concerns regarding implementation of an LMP-based system in California.

Under these circumstances, it is inaccurate to state, as the order does in Paragraph 42, that the CPUC supports the implementation of LMP. I hope that we can get there and I think today's work will help us do that. But that's not where we are at the moment.

Finally, last week's order suggests that FERC sees capacity payments as the quid pro quo for market power mitigation, with language that suggests that FERC will revisit market power mitigation only after the CPUC adopts a resource adequacy program in our procurement rulemaking. FERC seems to be concerned that too much spot market mitigation will result in inadequate forward contracting, inadequate planning reserves, and over reliance on spot markets.

I can assure you that we will not let this happen. In our procurement proceeding, we are addressing requirements for resource adequacy in the state in general.

The ISO had proposed to include resource --reserve requirements for resource adequacy in its market redesign. The PUC argued for time to allow the state to adopt the rules instead of FERC. We intend to follow through and adopt rules to insure the necessary power is on-line and available when it's needed. You will hear more about procurement this afternoon from the Director of our Energy Division. Our draft decision is due out in less than two weeks, November 18th.

Despite these misgiving and reservations, to wrap up, I want to emphasize my emphatic desire for this

Commission to work with the FERC. Too much is at stake for us not to strive for common ground. After all, at the end of the day, we're all charged with the same charge, which is to serve the public interest in California and nationally. So I look forward to a very productive meeting here and that we all approach it in a very positive and conciliatory way.

Thank you, Mr. Chairman.

CHAIRMAN WOOD: Thank you, President Peevey.

Generally, before we move into panels this morning, I would ask if any of our colleagues here -- if they don't have anything they want to add before we jump in.

COMMISSIONER LYNCH: I appreciate FERC Commissioners and Staff coming to San Francisco to discuss the design of open energy markets to eliminate the gouging and manipulation that occurred in the first attempt at deregulation. Hopefully, we will all learn from the egregious mistakes of our predecessors in designing and implementing the new market.

Any attempt to design a deregulated market will face serious challenges. I am very concerned that this attempt, by overriding the consumers and coordinated judgment of the California energy agencies most responsible for ensuring that the lights stay on in California is doomed to repeat the horrendous history of California's recent energy debacle. By overriding many of the basic protections requested by the ISO and by layering on additional payments to and opportunities to profit by the energy -- in this market, that FERC may be designing a market that is doomed to recreate the reliability problems and certain -- that California recently endured.

Further, by boxing in the -- contracts with an inability to hedge against the price volatility sure to be experienced in this new design, the FERC may exacerbate the problems inherent in the contract start. But I will be listening today for indications that the current market folks at FERC will listen to and learn from California's best advice and counsel.

But I am also deeply concerned about the failure of today's agenda to include any existing consumer representatives. While it may be Washington's practice to hear only from market participants, in California we welcome consumers and all representatives of the public affected by our policies to present and be at the table. This agenda does not include all market participants. Failing to include even wholesale buyers by scaling the technical conference to the wholesale seller side, I'm concerned that the record developed may be biased. A market developed with a bias in favor of sellers will simply not work and will recreate the problems that California has had a such good experience with.

So I would urge both my colleagues and FERC Commissioners to listen to the consumers and wholesale buyers as well --. I believe we would all benefit from inclusion for a more robust debate an array of experts than will be presented here today.

CHAIRMAN WOOD: Thank you for those thoughts.

(Laughter.)

CHAIRMAN WOOD: I think it's perfectly acceptable that everyone speaks their opinion.

How about any of the other commissioners, Commissioner Brown, Commissioner Kennedy? Do you have anything to add?

COMMISSIONER BROWN: Well, I think we've come a long way from where we started in the standard market design and I appreciate FERCs willingness to listen to the voices of the State Commissions and particularly our own state.

President Peevey has pretty much laid out in his letter to you our primary concerns. And so with an open mind and your willingness to work together with state and Federal cooperation. And with state and Federal cooperation, I approach this problem and I thank you for coming out here to take the time to deal with these rather taxing issues.

Thank you.

COMMISSIONER KENNEDY: Thank you.

Thank you very much for coming out here and spending your time and your attendance working to resolve any outstanding issues. I think we're at a major crossroad and the most important thing is that we move quickly to resolve any issues and not simply drift. We have a very, very important task and time is not our friend, especially here in California. We could easily be facing another crisis in terms of supply two years from now, with transmission constraints, et cetera, so it's very important that we place a high priority on action and not just debate in the next foreseeable future.

Thank you.

CHAIRMAN WOOD: Thank you.

At this time I'd like to turn it over to Shelton Cannon of the FERC Staff to introduce the first panel for today.

MR. CANNON: Just a couple of comments, as far as time. Quickly, the organization of today's conference, we're trying to focus -- which we're fortunate to have had both the MDO2 filing presented to us, the conceptual filing, as well as the order -- which we hope to use as an organizing principle for the state's conference. It's an ambitious agenda, we've got a lot of ground to cover. Our morning here is going to end at 1:30 for lunch -- 4:30 Eastern time.

(Laughter.)

(Simultaneous discussion.)

MR. CANNON: In the morning, we're going to be trying to focus on some overlapping issues associated with the implementation as well as the transition to a new market redesign, sort of how do we go about getting a good market redesign up and running.

The afternoon is more of a step back and look at the big picture, look at what the interrelationship is between market rules, between resource adequacy, between mitigation -- how all those pieces of the puzzle sort of fit together. And also how certain decisions that California will need to make going forward, how they fit into sort of the larger regional context and then into sort of the Western-interconnection-wide point of view.

We've had a number of these technical conferences and one lesson that we've learned from them is that they seem to be more productive if we stay away from just canned presentations and try to have more of a dialogue. So to that end, we've asked our panelists today to keep their remarks, their opening remarks, relatively short, sort of a three- to five-minute rule and we'll be giving you the high sign when it's time to have to come off and pull you offstage there.

But we thought that we want to try to keep away from canned presentations, keep things more focused. My role is going to be trying to introduce the panel, trying to keep people somewhat on topic, and then provide the basis for panels to talk to one another and set up questioning from the Commissioners, as well as from Staff.

The theme today, if I have one, is going to be let's -- it's fine, we'd like to hear from everybody's point of view. If people have problems with what's been proposed, we very much want to hear that. But we'd also like people to propose solutions and come to the table with ways to make things work. If you don't like what has been proposed, what do you like?

I'd like to underscore FERCs commitment and our Staff's commitment to work with all market participants, consumer groups as well as everyone out there in the marketplace. We want to try to keep this dialogue going, try to build some bridges and work out results that make sense from California's point of view and also make sense from FERCs point of view.

So with that, I'd like to introduce sort of our first two speakers. And this will sort of be somewhat of a departure from the panel format, but we thought it would be useful to have the California ISO make a short ten-minute presentation roughly in terms of what they propose as the sort of current market design issues.

We have Spence Gerber here from Cal ISO, welcome.

He is the -- Director for MDO2. And then we also have J.B. Shipley, who's in our office, and who will be giving an overview of the recent MDO2 conception.

With that, I'm going to turn it over to Spence.

MR. GERBER: Thank you, Shelton. I appreciate it.

Good morning, Chairman Wood, President Peevey, the Soft Margin Commissioners. I appreciate the opportunity to be here to give you a brief update on where our activity has been. And, as indicated, it is somewhat a canned presentation just to kind of maybe set the level of what we're accomplishing from the implementation perspective, not so much about the rules and the design itself.

Speaking on behalf of the California ISO, I really appreciate the timeliness and the clarity of the order that you put out on October 28th. It's very good because it validated some of the work effort that we have already gone into in putting forth our MDO2 implementation effort. It recognizes, as people have indicated in opening remarks, that there's still a fair amount of work to do to bring this to a close and to put together a comprehensive package that achieves all of the goals that everybody is trying to do from the clear rules in the wholesale market, protections for consumers, and making sure that we don't repeat any of the situations that we've had in the past in the restructuring.

I think we're still assessing what impacts the order has on our implementation effort with the open items that we will be discussing later today. And that will, in part, dictate where we go with our implementation schedule.

The good news is -- and we've been presenting this with code words here, Phase 1(a). I apologize for that but I think many of the participants that are familiar with what we've been doing are -- if I try to say it some other way, sometimes they get confused.

But that's our automatic mitigation procedure. It's been in place for over a year now. We've hit the conduct threshold numerous times, but it has never triggered a mitigated bit. So, you know, you can take from that whether or not that's effective mitigation or not or if it was just circumstance that got us here, but it's in play and it's -- you know, with success, I would say, but there's different varying degrees of what success means there.

It's important to recognize that that automatic mitigation procedure was applied to our existing real-time dispatch on our existing system, so it was a little bit easier to get there in terms of implementation; it didn't take quite the effort that we're engaged in right now. And this would be our -- what we've characterized as our Phase

1(b), where we completely change out our real-time economic dispatch program into an optimization program and we also add the uninstructed deviation penalties that the Commission granted us, pending ability of the suppliers to update their unit information in real-time.

So that really is -- this Phase 1(b), as we characterize it, is one of the major changes to our software system. So there is an increased level of complexity that comes with that, because it's not just dropping in a new software package, but it is -- the underlying systems that come with it are being changed out at the same time.

We're set to get there still February 1st, 2004. It will be a challenge to meet that implementation date. We're currently continuing to discuss with our market participants -- we're in our market simulation phase and we'll establish what the success of that criteria is with them to go ahead and make sure that both sides understand how it works, make sure that it does work, and that there won't be any surprises when it's implemented. I think there's really -- we'll be at peak point probably towards the end of December, where we -- with the cooperation of the market participants, determine whether or not we are ready to go and drop this into place on February 1st.

Moving along, we've been talking all along about a phased approach for a forward-energy market and LNP. In our last year of putting together the pieces, we have determined that a single stage approach to introducing an integrated forward-market and an LNP pricing scheme is now in the best interests for a number of reasons, so the current plan would collapse this phase two to phase three implementation into a single implementation date.

I think one of our challenges is to remember that we need to have a meaningful LNP trial period and I think we've got a plan to do that. There's some cost savings for the ISO and if I see them on my side, I think that it's certain that the other market participants will see them. The types of things that may become evident in my next slide is that, in order to have a phased approach, you have a lot of testing and integration work that you have to do in both a forward-energy market and separate LNP implementation that you can bring together and save a significant amount of work effort in having a robust testing environment.

And then there are some other places where we've recognized savings, for an example, in our settlement system there's several million dollars worth of savings of not having to carry a separate schema for just a forward zonal market, that we can bring those two together and find some savings there also.

And I think the other important piece is that, as everybody recognizes, there are still some structural flaws in our market that we believe will be addressed by this, particularly interzonal congestion issues, and that have all congestion treated in a forward-energy market rather than moving it to real-time, where you have less time to react. And the sooner that we can get there, I think some of the benefits that will derive from LNP prices can be achieved.

(Slide.)

This last slide is my Christmas present to everybody. Hopefully it's colorful enough. There's a whole lot of things going on here. Certainly there's a lot of interdependencies and interplay among the various projects that we have within our program. Stakeholders, starting with our ISO Board, the state commissions, the FERC Commission, that we have to be mindful as we go through this. I'm not going to dwell a lot on this particular slide. There's a lot of information here. We will continue to post this kind of information on our web so people can see where we're going. But it's a high-level roll-up of what we expect to accomplish in the next two years based on what we know now.

And I'm careful to put that caveat in there because some of these open issues continue to be discussed and if there's changes to the way we implement our software, we'll have to make those adjustments and that certainly can have an impact on this implementation schedule.

I think the three projects in the middle of the page: our integrated forward-market LNP, our congestion revenue rights and our settlement system are the key outward facing systems that I think people will recognize that are important for market functionality, but all told there are over 15 projects within this to bring all that functionality together in an integrated fashion.

And that's -- as we get over to the right-hand side of the chart there in the middle of the page, there's several places where you see some testing that starts, and right now it's projected for the first quarter of 2005. And, based on our experience and understanding of what it takes to put this kind of complex system into play, it's very important that we get to those testing phases, it's very important that the market participants are comfortable that it's functioning the way that it is. And, in particular in California, it's very important that we see some results of the what I would characterize as the LNP trial period here to put this into play and see what the results are, so that people understand and can see that it derives the benefits that we're seeking here.

And then down towards the bottom of the page on the left-hand side, there are still some key milestones that are important to making sure that we have all the pieces put together, certainly the procurement proceedings. There's also additional work that was laid out in the order that we need to continue with the market participants. We're still in the process of determining what those priorities are, which ones need to be resolved at first so that we can make sure that we can describe that functionality to the vendors that will be providing us with our software, so that we don't go down a path of having to do a lot of change orders later on this.

So again this is -- my experience tells me that throwing a date out there of when things are going to be done when it's two years in advance is sometimes writing a check and then you have to go back and check the balance of the account. But I think it's important to recognize that this is a timeframe in which other similarly situated ISOs and RTOs have used as a duration for implementation of this kind of project. And, again, I think closing out those open issues as we go along, bringing more certainty to the schedule, that we're certainly a lot better off now than we've been over the previous year and we appreciate again having the order and the clarity that that brings to our implementation effort. But as we work through these other issues that we'll be discussing today, those will also inform how soon we can get there and with what speed.

CHAIRMAN WOOD: Spence, what did we not answer that is an impediment for moving forward on software issues?

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Basically, what is the date that you start having charge order charges kick in for changes to the software design?

MR. GERBER: I think if you -- on the chart there, we've kind of put a date out there down at the bottom there in Detailed Resolution of the Stakeholders. That kind of gets into the development period. And if we're going to have discussions about some of the contentious issues -- there are some instances where, for a reasonably -- what I would characterize as, you know, in the $50,000 range that you can get some flexibility with your vendor to do things one way or another, to the extent that that makes sense and we can go forward so we have that option and we'll continue with that if it's, you know, reasonably financially prudent.

But there will be other issues that we need to make sure that we understand what they are.

But it is within the -- probably the next four or five months, and it really does accelerate the progress. I think Commissioner Kennedy touched on that, is that we feel compelled to try to get these things resolved in a very timely fashion so we don't push that date out for implementation.

CHAIRMAN WOOD: So just to burrow down a little deeper, by working through the collaborative process we talked about earlier in the next few months, early months of

'04, we get answers to what --

MR. GERBER: For example, we need -- what you've laid out in front of us -- and, I think some of my colleagues can speak to it with a little more authority than I can, but resolution of our CR allocation, how do we implement that software? There are still open issues on local market power mitigation, market power mitigation, what form is that going to take and how does that come into the software to insure that we get the protections that FERC people asked for. Those are some of the key ones. Also, resolving some of the functionality within the residual unit commitment that, in our minds, is still open are some of the key areas.

CHAIRMAN WOOD: Thank you.

MS. SHIPLEY: Good morning, Commissioners. It's nice to be back in San Francisco working to bring people together to find solutions for California's energy markets.

On October 28th, the Federal Energy Regulatory Commission issued an order on the Cal ISO July 2003 market design proposal. You later responded to the Cal ISO's request for Commission guidance on several market elements, many of which will be discussed today.

Briefly, the Commission approved a security constrained integrated forward market and locational pricing to manage congestion. The proposed full network model will create a detailed and accurate model of the transmission grid to identify constraints so that the Cal ISO can adjust schedules accordingly, thus eliminating the acceptance of infeasible transmission schedules and the distinction between inter- and intrazonal congestion.

According to the Cal ISO and various market monitoring reports, the current zonal congestion management policy has resulted in increasing intrazonal congestion costs, inefficient dispatch, and opportunities for manipulative trading strategies. The Commission approved the Cal ISOs proposed congestion management system which would solve these problems and create -- transparency.

With this new design, the Cal ISO will be able to recognize all transmission bottlenecks so that schedules submitted in the day-ahead timeframe can actually fit on the grid in real time. It will allocate the use of limited transmission facilities to energy buyers and sellers in a non-discriminatory and efficient manner, and it will make the best use of transmission and generation resources to serve load and provide system resources on least cost basis.

The Commission also supports the Cal ISOs proposal to charge load and aggregated price. This is a reasonable approach to introducing locational pricing while minimizing impact on load and this approach has proven successful in other markets.

In order to preserve existing rights and to provide customers an opportunity to protect themselves from the financial impacts of congestion, the Commission supports the adoption of congestion revenue rights as a risk management tool. Both the Commission and market participants need further information on the allocation of rights, and in its order the Commission required Cal ISO to continue to work with parties and to file detailed information on the proposed first-year allocation when it files its proposed tariff.

Existing transmission contracts also pose transitional issues for any market redesign. The Cal ISO has attempted to address these issues through CRRs. However, there are still concerns remaining regarding the transition to the redesigned market, particularly the reservation of unused capacity after the day-ahead timeframe.

The Commission's preference is that this unused capacity or phantom congestion should be alleviated to the extent possible in a way that is consistent with contractual rights. The Cal ISO has committed to working collaboratively to resolve this issue and we encourage the Cal ISO and market participants to continue to work together towards a solution.

In ensuring that sufficient resources will be available to meet its load forecast, the Cal ISO has been relying on the ad hoc waiver process associated with the must offer obligation. This process has served as a rudimentary unit commitment tool to the Cal ISO and it has proven to be problematic in its application. The proposed residual unit commitment process will provide a more rational and transparent unit commitment tool to the Cal ISO to insure reliability of these costs. The Commission supports this approach.

Regarding the issues of mitigation and resource adequacy, the Commission stated it believes the various elements of a regional market should work well together to produce an efficient, well-functioning wholesale market for the benefit of customers over the long term. There are important interrelationships among wholesale market elements, such as the energy market design, the system for managing congestion, research adequacy revision, and the means for mitigating market power. Achieving an appropriate balance among these factors is critical to a well-functioning wholesale market. As part of this balance, market power mitigation should address market power concerns without undermining -- and long-term resource adequacy.

The Commission wishes to insure that the Cal ISO will have the appropriate tools at its disposal to protect against the exercise of market power.

With this backdrop, the Commission has decided that the best avenue to address the Cal ISOs proposed mitigation was to have a technical conference that will build upon discussions begun here today. The Commission, however, offered guidance in several respects:

First, the Commission modified its proposed must-offer obligation to require that generators offer in the real-time market unless the Cal ISO finds they are not needed in the day-ahead market. In its order, the Commission advised further discussion of this proposal among market participants and the Cal ISO.

Second, the Commission found that issues such as resource adequacy and market power mitigation should not be dealt with in isolation. Without the benefit of a complete market redesign proposal, the Commission cannot make informed decisions on all aspects of the Cal ISOs proposal, decisions that impact the ability and --, the reliable operation of the grid, and the ability to attract and retain investment.

In summary, the Cal ISOs proposed comprehensive market design represents major improvement in how the Cal ISO operates the grid. The changes are designed to fix flaws and encourage desired market behavior and the market is designed so that market rules closely support grid operations. The ultimate goal is a robust and competitive spot market that enhances reliability and lowers cost.

The Commission has acted in recent orders to provide some preliminary guidance and to foster a continuing and collaborative process to complete this market redesign effort. We are here in this technical conference prepared to further the process and it is out hope to flesh out some of the pertinent issues with the panels here today.

We will end today with perhaps not all of the answers, but at least a process for how to move forward in the areas where we have outstanding issues and questions.

CHAIRMAN WOOD: Thank you, J.B.

MR. CANNON: Thanks.

Can we get our first panel up here?

(Pause.)

MR. CANNON: Our first panel this morning is going to look at implementation issues related to locational marginal pricing and grid congestion management and congestion revenue pricing.

I think what we hope to get through this panel is a better understanding of the power congestion management system and its workings and, very importantly, how customers can protect themselves or hedge against --.

With us today -- which side do we start on here -- with us today we have Lorenzo Kristov, who is the principal market design architect from the California Independent System Operators. There's Phillip Auclair, who is Manager of Market Regulatory Affairs for Grant America, Inc. We have Ronald Nunnally, Director of Federal Regulation and Contracts for the Southern California Edison Company. James Caldwell, Policy Director of American Wind Energy Association. Joe Desmond, the President and CEO of Infertility, Inc. on behalf of the Silicon Valley Manufacturing Group.

And with that I'll give it to Lorenzo Kristov. Everybody, if you could try to keep your remarks to under five minutes, that would be very good.

MR. KRISTOV: Okay. Thank you very much.

Good morning, Commissioners. Thank you for the opportunity to be here. I want just to provide a few opening comments just to provide some perspective on what the ISO has been trying to do with implementation of LNP and CRRs and allow maximum time for your questions.

I want to make it very clear that when we go back to the motivation behind ISOs market redesign it's fundamentally rooted in fixing congestion management. Congestion management, already I recognize that's a technical term and to some people that's a term that offers difficulty but it really goes to the heart of managing access to the grid and making sure that the grid oscillates reliably. Congestion management means relieving traffic jams and allowing things to be scheduled in such a way that it won't overload a facility.

Since the beginning of ISO operation, it's become gradually apparent over time that the zonal congestion management market has some problems with it. Those problems have become exacerbated with time and, more recently, we're aware of areas where the generation is connecting and it's very difficult to accommodate that due to lack of active transmission but, more importantly, there's no way to manage that on a time basis ahead of real time. It's all become a real-time operational challenge.

So fixing congestion management is something that's been on our minds for a long time. We embarked on it in January of 2000, in fact, with a major internal project devoted to congestion management reform. That project has become somewhat sidetracked because of the prices that arose in the summer of 2000.

We recognize, and I think most parties recognize that the ISOs congestion management system was not a fundamental cause of the crisis and fixing it doesn't fundamentally in itself relieve the crisis. What it does do, is it makes a critical piece of California's infrastructure -- namely, the transmission grid and the ISOs role as operator of that grid -- function in a more efficient and reliable manner and in such a spirit which would help the market but is not in itself sufficient to deal with all the causes of the crisis.

That being said, the key element to fixing congestion management then is to, on a day-ahead basis, use a realistic model of the transmission grid, one that shows all the interlinkages in that network, that realistically models their constraints and enforces them, so that when we establish a schedule, a plan to use the grid on the next day, that schedule is feasible, exclusively capable of flowing on the grid, respecting all the constraints of that grid. The zonal model does not allow us to do that. What we propose to do, using the full network power, will allow us to do that.

Once we make that fundamental threshold decision to use the full network model, then the next piece that comes with that is that we end up having a day-ahead energy market integrated with congestion management because we have to trade adjustments across the different scheduling parties in order to clear congestion.

That's getting a little bit more technical, but the fact is that what the other ISOs do in the East and what we've learned from their experience is that this integrated method based on integrated energy and congestion management and based on an accurate network model is a reliable and proven way of doing congestion management effectively and efficiently.

Now that being said, we recognize that the nodal prices that result from this congestion management approach are extremely important for the pricing of supply resources, because it provides the right incentives for the operators of those resources to operate in a fashion that supports grid reliability.

Those same price signals are not nearly as important to provide loads. And given a lot of the concerns about impacts on loads of high prices in certain areas, we recognize that we did not need to include in our proposal pricing loads at locational prices.

Moreover, we recognize the arguments that were made, and we agree with those arguments, that there is something of an equity case to be made: that the transmission grid was built under a prior regulatory framework in which competition and generation was never contemplated, locational pricing for loads was never contemplated, where utilities -- integrated utilities who operated both generation and transmission made investment decisions full optimizing those two types of upgrades in different areas. So it would be unfair to have consumers who inherit this system built under a different regime suddenly be subject to the congestion price impacts that occur in congested areas.

That's why our proposal contains some critical elements that we believe insulate consumers. Those critical elements are load aggregation and allocation of congestion revenue rights. These are beyond mitigation, local market power mitigation and other important market agreements that we've talked about in other panels.

But specifically load aggregation means that all these loads will be paying aggregated prices based on three geographic areas, defined by the major investor-owned utility transmission service territories: PG&E, Southern Cal, Edison, and San Diego Gas and Electric. And encompassed within those geographic areas are all the municipal utilities, direct-access consumers, as well as utilities' native loads, as well as entities like the state water project that are not formally served through a load-serving entity. But all of them will be able to schedule and be served by those aggregated prices.

That being said, now we have a proposal for congestion revenue rights. That's also a key element. That proposal is simply taking our existing FTRs, our firm transmission rights and modifying their design to fit with an LNP type of market that we're proposing. And once we do that, we now have a different type of product but one that fits within the congestion management model and there will still be risks on the side of load-serving entities to face congestion charges for serving those loads. Those risks arise from the different locations from which they're bringing their supply resources.

So we propose to allocate to them a set of congestion revenue rights that will effectively, over the course of the year, keep them neutral with respect to congestion charges. In other words, a package of rights which provides revenue stream that's equal and opposite offsetting to the stream of congestion charges they face. That's our objective at this point. We have initiated and we will be talking with stakeholders and providing all of you with information on the outcome of studies that will explore exactly how to do that, and that's part of the on-going CRR allocation process.

We've also tried to address some of the questions that were raised in the notice for this meeting. We've structured CRRs in such a way that they will be annual in the term length, as well monthly, so things like seasonal variation in these can be addressed through monthly allocations. There will be a peak-period CRR and there will be an off-peak period CRR. So, again, daily variation in loads -- we believe this package will enable load-serving entities to get a package that meets their needs. Similarly, load growth loads who leave one load-serving entity and go to another, all of these can be taken into account through changes in the monthly allocations. In the same manner, transmission upgrades that get awarded CRRs as they come on in the middle of an annual CRR award period can be given an allocation in the monthly process.

MR. CANNON: Mr. Kristov, I hate to make an example of --

(Laughter.)

MR. KRISTOV: Go ahead.

(Laughter.)

MR. CANNON: If we can maybe have some of the discussion -- it sounds like you were getting to some of the questions that we're posing and that's great, but maybe you can do that again more in an interactive format.

MR. KRISTOV: Okay. I'll make -- if I may make one closing comment --

MR. CANNON: Sure.

MR. KRISTOV: Just the point about collaboration with the state: the ISO is working closely with the Public Utilities Commission on the CRR allocation process. We will be continuing that much more intensely over the coming months, as well as with other state agencies in this process.

Thank you very much.

MR. AUCLAIR: Good morning, Chairman Wood, President Peevey, Commissioners, and Mr. Saltmarsh. I'm pleased to participate in today's conference.

First, I would like to acknowledge the tremendous efforts of the FERC, the California ISO, and the California PUC in working with the industry to resolve some very complicated issues.

Today I will address the following question that FERC has asked from the panel: Does the California ISO MDO2 proposal provide market participants who wish to hold CRRs an adequate opportunity to obtain them? The answer to this question is unfortunately no. Only a CRR option approach immediately and unconditionally provides all market participants an adequate opportunity, as well as an efficient mechanism, to value the purchase of these property rights to congestion revenues. An option approach is critical to assure that the true owners of these rights, future core and non-core consumers, are properly protected and compensated. Moreover, an option approach facilitates the development of competitive CR secondary forward contract markets which transparently price and efficiently allocate these instruments.

Most recognize that workably competitive spot markets cannot develop without robust competitive forward markets. Give the locational dimension of electricity, it is imperative that competitive CR markets develop as soon as possible. The California ISO, however, proposes to allocate CRRs to existing load-serving entities on behalf of their customers and to the state water project. Without additional rules, transmission-owning LSEs, load-serving entities, under the California ISO proposal can easily become de facto property owners of CRRs with little incentive to sell even unused rights to other market participants. This would thus eliminate supply options for both the core and non-core customer base.

It is Merit's hope that the proposed California ISO CR allocation approach is only a very short transitional future to a superior CRR option approach. In the meantime, under the allocation approach, the California ISO and California Public Utilities Commission need to implement rules to insure that existing transmission-owning LSEs do not indeed become de facto property owners of CRRs. Only then can the benefits of CRRs be made available to all market participants, including the often-forgotten retail load, in a non-discriminatory and comparable manner.

There are two necessary, though not sufficient, conditions that must be met to insure that existing load-serving entities not become de facto owners of the preallocated conditional revenue rights. The first necessary condition is California ISO and California Public Utility Commission rules must make it explicit that CRRs do not belong to LSEs. The second necessary condition is the California PUC must adopt rules to allow third-party supplier access to the retail load that owns the CRRs.

Please let me elaborate on these two conditions:

Condition 1, California ISO rules must make it explicit that CRRs belong only to retail load, core and non-core, and any other participant who pays for the transmission infrastructure. Thus, an LSCs only role is to administer the accounting associated with CRRs on behalf of the load it serves, be it residential or commercial or industrial. As such, all CRRs must be portable. That is, CRRs must automatically travel with the load if it decides to switch suppliers. The new supplier would then administer the CRRs on behalf of its new load.

Under no circumstances should a load have to wait for a month, a year, or even two years for a CRR allocation process to take place before it can switch suppliers. This is especially significant to the large non-core customer group on a pure economics basis.

As a side note, I'm a little confused by the California ISO proposal that provides an LSE the right to sell CRRs in the California ISO auction or in secondary markets. If load really owns the CRRs and these instruments are to be allocated to load, then how can the California ISO confer the right to sell CRRs on the load-serving entity.

Condition 2, the California PUC must adopt definitive and clear rules to allow third-party supply access to the retail load that owns the CRRs. Under the California ISOs allocation approach, FERCs objective to provide market participants with adequate access to CRRs can only be achieved by satisfying the following objective: provide third-party supply with adequate access to the load that has the CRRs.

So if the California PUC does not adopt rules that, at a minimum, permit a core/non-core structure, then by definition the California ISO proposal does not provide third-party supply adequate access to CRRs. Furthermore, if the two necessary conditions that I mentioned above are not met, then California will face a situation where transmission-owning LSE, load-serving entity, becomes a de facto congestion revenue right property owner on its own constrained transmission system. As such, all efforts to establish non-discriminatory and comparable access to constrained transmission capacity will have come full circle to the situation California faced before it unbundled transmission operations in pricing from generation.

Thank you.

MR. CANNON: Thank you, Mr. Auclair.

Mr. Nunnally?

MR. NUNNALLY: On behalf of Southern California Edison Company, I'd like to thank FERC and PUC and the EOB for the opportunity to provide comments this morning related to the implementation of locational marginal pricing and congestion revenue rights. SE believes that continued dialogue among the stakeholders and the commissions in the collaborative manner that Chairman Wood described and President Peevey described I think is very necessary and helpful to ensure timely implementation of the ISO revised market design.

I'd like to cover just three points: First of all, SE supports LNP as a proven method for efficiently managing and pricing congestion. It is a critically needed solution to existing costly problems associated with intrazonal congestion in the Cal ISO grid today. We're hopeful that, given the guidance of the FERC order last week, that we can now shift the focus of this discussion from considering LNP to actually implementing LNP.

Secondly, while LNP provides important price signals for short-term operating decisions, it should be recognized that LNP is not the most significant factor driving new transmission investment due to the long lead times of major infrastructure additions. Transmission investment must be stimulated by clear responsibility for providing new transmission, by assured recovery of prudent costs -- including abandoned projects authorized by an independent planning process -- and by equal opportunity for all regulated transmission utilities to receive incentives for new investment.

Third, load-serving entities must be allocated sufficient CRRs to mitigate congestion cost risks faced by customers who pay for the transmission grid. We strongly endorse FERCs findings that the Cal ISO proposal to allocate CRRs to LSEs is reasonable. However, the focus again needs to shift to improving the ISO CRR allocation methodology.

Although SCE supports increased forward-energy contracting, it is premature to know whether or not the CRRs proposed by the ISO will sufficiently hedge forward congestion cost risk until the ISO completes development of its allocation proposal. Therefore, we support FERCs directive to the ISO to complete and publish results of the proposed CRR allocation process before a definitive ruling on the CRR proposal can be made.

We are actively participating with the ISO in the development of those studies and their allocation process. While we recognize that the results of their studies are preliminary, we do have significant concerns with some of the study results that we have seen to date.

One of the primary concerns has to do with the objective function that is being used in the allocation methodology for CRRs. The ISOs current shift factor approach does not take into account the value of the CRRs to consumers and the financial impacts. It seeks primarily to maximize the quantity of CRRs, which doesn't take into consideration what is the most valuable CRR to retain. We think that's a refocus that needs to be taken by the ISO.

And secondly, the treatment of existing transmission contracts is a critical element in the allocation process in an assumption. And in making that allocation both to existing contracts as well as LSEs, we must find a process that doesn't discriminate between either party, but that comparably allocates those CRRs to all loads.

Those are the comments we'd like to offer today and we'll be glad to participate in the discussion.

MR. CANNON: Thank you.

Mr. Desmond?

MR. DESMOND: Thank you, Chairman Wood, President Peevey, Commissioners. I appreciate the opportunity to be here today on behalf of the Silicon Valley Manufacturing Group and offer some of these comments.

A little background on SVMG and why I think it's relevant: SVMG member companies employ more than 180,000 employees here in the Bay Area. Our members include both public- and private sector companies. They represent large and small businesses, manufacturing and non-manufacturing entities, single-site and multi-site customers. They are served electricity as both bundled-service customers, direct access, and municipal customers. SVMG is a frequent participant in some of the CPUC proceedings and CPUC initiatives to gather stakeholder feedback. And in general I can say that we support the efforts for wholesale market reform and the direction of Cal ISO in its implementation of MDO2.

But I want to make clear that I am here today representing business energy consumers in expressing these concerns, because businesses are ratepayers, too, and have borne a disproportionate cost of the California energy crisis. Having said that, let me share with you some of my concerns, as well as questions and clarifications I'm hoping that the panel can provide here today.

We believe that LMP can provide the appropriate price signal, but we are concerned that the Bay Area faces particular constraints. We have looked at some of the initial Cal ISO studies which indicate the significant price volatility that could occur in congestion in the Bay Area. What I am not clear is, for those of our members who are served by municipal customers, whether their existing firm transmission rights would translate to CRRs that would appropriately mitigate against some of this.

We also believe that this price signal can provide an appropriate source to encourage investments in more demand response, as well as distributed generation.

But we would ask that both Cal ISO and FERC consider easing some of the telemetry requirements to make load to participate in these markets, including the upcoming integrated forward market. They are very difficult when we look at opportunities to aggregate residential and small commercial load and tap into that resource as a way of mitigating market power.

I am aware that CRR follows load, and I appreciate the comments that Phil Auclair made. I think they're appropriate in our general approach to open access.

What I cannot comment on as an end-user though is whether obligation versus options are the appropriate way.

But what I can say though is that we have seen that the CRR balancing accounts are heavily dependent on the AC power flow model. And our concern is whether or not, depending on the control over CRRs, an SC, a scheduling coordinator, could exercise that market power based on under- or over-scheduling load to take advantage of and create revenues in a CRR balancing account. I don't have the answer to that, and so we would look to Cal ISO to demonstrate that that's not the case.

We also believe it's very important that the CPUC address the issue of long-term resource adequacy in a manner that would work with both the existing regulatory framework, as well as a potential framework that would enable a core/non-core approach. The mechanism has to function under both scenarios and we share, I think, both the Commission's concern and the Cal ISO's concern that we face the potential for another crisis here in the next two years. I know that's the subject of conversations this afternoon, so I'll limit my remarks on that.

What I would like to hear more about -- there were some interesting comments made in the testimony about constrained output generators being enable to set the clearing price. I say I'm interested because there was reference to environmental emissions constraints being applied to define a peaking unit as a constrained output generator. And given that the Bay Area relies on these peaking units, whether or not the Cal ISO software takes this into account in its modeling of the day-ahead market.

Thank you.

MR. CANNON: Thank you.

Mr. Caldwell.

MR. CALDWELL: Thank you.

Three quick points: One is the case for action, second is to note some very promising process improvements in the guidance order, and third is to make a couple of modest suggestions for moving forward and maybe probably add a little more -- one more brick in the load of the CRRs.

The case for action. A couple of statistics:

California ISO claims that they need about a 1.2 bid coverage ratio to keep the market liquid on their current design, while PJM consistently has operated for years with bid coverage ratios lower than 1.05. If you translate those numbers, that means something like 5000 megawatts of capacity on the California system, and means something like $500 million dollars a year worth of capacity costs. That's the stakes.

Now why do I think -- or why do we think that the difference between those two market designs? My hypothesis is Balkanization of the California grid into 20 some-odd quasi-control areas, and it seems to be growing by the day.

And that each one of these control areas are pursuing balanced schedules instead of balancing the system. And what we're giving up is the very nature of the network, the very reason why we interconnected the grid so that we can share and so that we can use the law of large numbers and the difference between coincident peak loads and the individual loads in order to lower the cost of serving us all off the network.

Statistic number two: The WECC and the California ISO transmission-to-pathload duration curves are invisible. They average under 30%. And they're getting worse. They are historic loads that are getting worse;

i.e., that the existing utilizations of the existing assets of the grid is getting less efficient over time at the same time that congestion is apparently increasing and we're calling for more new builds. That's an intolerable situation. We have to fix and use what we have now before we go off and build some more.

Hypothesis as to why that is: I think the principal reason is the concentration on the protection of the existing individual -- not network, individual -- physical --. Whether we call it phantom congestion or whatever we call it, the individual use of the network system makes for an inefficient allocation of transmission assets and we must fix that problem before we proceed any further. And we must do it now. The stakes are simply too large.

Some promising process -- the second issue I was talking about, some promising process improvements in the guidance order. Several places in the order there are statements like Well that sounds right, okay, it comports with policy and experience, but what we're going to require is that the market monitoring unit monitor on a routine basis trends in metrics that look at the efficiency of what we're trying to do. Report to us routinely about the trends in those numbers and be prepared to take action quickly if they change.

Most of these were for metrics that we don't normally think of, like convergence -- or divergence between day-ahead and real-time crises. That's an extremely important metric if we're looking for liquidity in the spot market. And the liquidity in the market is a very, very important metric for the health of the market. And we simply must continue to use these early warning signals, these advance signals that there is problems and then get on quickly. And I applaud the order for them.

A couple of modest suggestions: One, we need to expand that routine monitoring, reporting, early warning, advanced warning signals for changes in these balancing accounts. There's a lot of moving parts in this process. And what's happening in the balancing accounts -- which, by definition, they're supposed to balance, they're supposed to come out, you know, on average somewhere around zero. Well if we find the composition of those balancing accounts changing, if we find all of a sudden there is a predictable or a large increase one way or the other in that balance account, that's an indication that something is going wrong or something is different and we'd better drill down and figure out what that is, we've got to watch it in the beginning, we've got to be prepared to act. We talked a little bit about the CRR balancing accounts. I think that's one we need to look at. Another one is in the allocation where we put marginal losses into a balancing account.

Now I have to say that either the Commission doesn't believe what we filed in terms of full marginal losses, that is -- calculated full marginal losses essentially doubles the amount above what the actual losses are -- either they don't believe that or they don't care. If they don't believe it, I think we'd better monitor that, okay, and I'm willing to do that. If you monitor, you find out within weeks that that is indeed the case.

If we don't care, then I guess I'm speechless. Because what we're talking about is hundreds of millions of dollars a year in found money and I'll guarantee you that if we put hundreds of millions of dollars a year into a balancing account that we will have a food fight over who gets that balancing account. And that will be the focus of people's efforts is to get their -- quote, unquote -- fair share of that money. And if that money does not represent cost to the system, then we should not be reallocating.

Another modest suggestion is in the CRR records.

I'd like to add one -- and several of the panel so far have spoken to this. And that is does the CRR methodology allow for a clean efficient hedge for a long-term fixed price contract, pure and simple.

The wind industry today has enjoyed all around the country 20 year fixed price contracts for $30 a megawatt-hour.  If we're not able to do that in California because of the state in terms of the CRR allocations, that would be a pretty good indicator that we've got the CRR allocations wrong. If we can't do a long-term fixed-price contract, then it's wrong.

Finally, I think on CRRs, one more brick in the load, and that is that as long as we're talking about deregulation or, maybe better, competition in generation, then transmission policy becomes energy policy because the way we deal with the allocation of access to the existing grids and how we expand that grid becomes the driver for whatever it is that we're trying to achieve from a public policy standpoint on the generation side. So if we have goals of resource diversity, of environmental importance, of renewable portfolio standards, then the important driver and the important consideration becomes transmission policy. And CRRs are the policy lever that drives what happens to the generation side.

So I guess I would submit that no matter what we do, no matter what we come up with for an allocation process on CRRs, that there will be an on-going need to have a thumb on that allocation by the folks who are in charge of the policy for the generation side. And in this instance, and I think what we're saying is that the RSCs or, in California, the state needs to have the continuing work and a continuing view of the CRRs as we go through time.

Thank you.

MR. CANNON: Thank you.

Questions from Commissioners?

VOICE: I heard some different things listening to the panelists and I kind of would love to hear some of the responses back. I heard Mr. Auclair talking about advocating an auction as opposed to an allocation and I'm interested in hearing what the Cal ISOs response to that is.

I also heard Mr. Nunnally talking about certain concerns that he had with regard to the allocation methodology. And I'm just wondering if you could sort of address some of those and what your game plan is for trying to resolve this.

MR. KRISTOV: Certainly. We've had conversations with people in the New York ISO who started doing an allocation -- an auction process, rather, and looked into the alternatives before coming down on the side of allocation. And I think a very important consideration for us was the complexity for something that we're doing for the first time, where there's a lot of concern about uncertainties, about what the impact of LMP would be and how it operated on the system, how do you manage the risks if you are a market participant, a load-serving entity, et cetera.

In order to do an auction process, there still needs to be recognition of the entitlement of loads to rights. And that entitlement then gets expressed through an allocation of auction revenues. The technical exercise you go through to figure out how to allocate auction revenues is essentially as complex as the allocation that you go through -- the process you go through to figure out an allocation of the rights themselves. Except it adds an extra step. You allocate the congestion revenues first, then you require all the load-serving entities to engage in the next step, which is the auction and bidding and all of that process. We wanted to make it easier, at least in the beginning, for load-serving entities to see that their rights are taken care of, so we came down on the side of allocation initially.

I want to add to that though the concern about where the entitlement lies and here Mr. Auclair and I completely agree. The ISO believes that the rights belong to the loads themselves and, as such, when a load switches from one supplier to another, that property right moves with the load itself. And that's the entity that's receiving the right.

In addition, regarding load-serving entities trading in the market, what we're considering along that policy is that the rights that belong to loads continue to belong to loads no matter what. But we can't preclude a load-serving entity from coming into the auction process that follows the allocation and bidding to take certain positions in that market. They have the right to do that, as any other market participant.

COMMISSIONER BROWN: Mr. Kristov?

MR. KRISTOV: Yes, sir.

COMMISSIONER BROWN: If I could just ask, do you see the danger in the auction that you'll have speculative or possibly anti-competitive pressures being applied to the auction itself so that you have people holding these CRRs?

MR. KRISTOV: Well, that certainly is a danger we'd have to look at very carefully, but an important --

COMMISSIONER BROWN: It gets like a commodities market after a while.

MR. KRISTOV: Well, it does, but an important safeguard is the presumption that the loads, as their representative of load-serving entities, have an entitlement to auction revenues. So if this particular set of bidders into that market have the entitlement to revenues, then in a sense that gives them a certain freedom to be able to bid very high to get the rights that they need. So what other ISOs have discovered is that essentially allocating them the revenues is economically equivalent to giving them the rights to begin with. Now, as we've said, it comes down into a matter of simplicity to do it the way that we're suggesting.

Did I answer everything --

MR. CANNON: I didn't answer Mr. Nunnally's question, so let me remember which specifically did you have in mind?

VOICE: Perhaps Mr. Nunnally could reiterate. He expressed certain concerns that they had with regard to how this allocation methodology would work.

MR. NUNNALLY: Yeah, I think the two questions or comments that I made. One had to do with the objective function of the allocation methodology which, as I understand today, focuses on maximizing the amount of CRRs by when there is not a sufficient allocation or there are more CRR requests than feasible, it would allocated based on the most effective reduction in terms of generation and doesn't take into consideration the value of the resource that would be protected by that CRR, hence, the financial impact on customers is not acknowledged.

MR. KRISTOV: Okay. There's a couple of aspects to that. Yes, our initial CRR study did not look at economic values at all. This is our first cut at this study and, granted, that's why it's very limited in the conclusions. It just looks at total megawatt quantities, how many megawatts of CRRs is it possible to release given the configuration of the system. So we need to go a further step and bring economics into that.

One of the ways that we're going to do that on our next round of study is actually look at the congestion charges associated with a load-serving entity's scheduling behavior and compare that with the congestion revenues that they will get from the CRRs. That's one aspect.

But another aspect regarding the objective function in allocating CRRs -- we're in a little bit of a quandary and so we'll have to discuss this further I think between our technical staffs. And the quandary is this: that if you're doing an allocation process, you essentially treat all requests by load-serving entities on an equal basis. In other words, you don't associated bid values with that, because you don't want to discriminate among the different loads who are being served. And that's one reason why the objective function is structured that way. When you go to an auction process, then parties put in economic bids and then you consider the bids. But, as I say, we're willing to continue discussing this between our staffs.

COMMISSIONER BROWN: Could I just add a direct question to Mr. Caldwell, because Mr. Caldwell's emphasis was really on the upgrading of the grid itself, wasn't it?

MR. CALDWELL: Well, the use of the existing grid and then the upgrade.

COMMISSIONER BROWN: And so, I mean, what is your reaction as you see us trying to build a CRR-type process?

MR. CALDWELL: Well, I guess I'm reminded of the old adage about putting your eggs in a basket and then watching that basket. And that certainly is the basket to watch in this process. And again, I think the important thing is is okay, yes, we're all -- we all like to think we're experts and we all like to think we know how to do this, we all have a lot of good theories and there is a lot of good relevant experience around the country and around the world in these kinds of things. So it's not like we're embarking on some, you know, otherworldly experience.

COMMISSIONER BROWN: Like 1896 or something.

MR. CALDWELL: Yeah. So I don't think we need to be afraid of this and I don't think -- but I think the point is that I think the mistake, the process mistake that we made the last time around was assuming that we were smart enough to get all these moving parts perfectly correct in the first place, getting total agreement on all the people, signing off on tariff language and all these sorts of things, and then making it very hard to change that tariff language. The only way you could do it was through a litigation process 3,000 miles away before a Commission that wasn't here. And that was our mistake.

And I think that yes, we can do a good job initially of allocating CRRs. I would be totally shocked if, 10 years from now, there wasn't significant changes to whatever we came up with.

COMMISSIONER BROWN: Does the CR process, though, in some way inhibit the, you know, the urgency that you're talking about to upgrade the existing --

MR. CALDWELL: No.

COMMISSIONER BROWN: -- for instance, you don't think it gives us --

MR. CALDWELL: No, I think the CRR process of allocating and dealing in financial rights as opposed to physical rights is the key, the key improvement that we're talking about here in terms of utilization of the existing system.

COMMISSIONER BROWN: How does that --

MR. CALDWELL: We can't be afraid --

COMMISSIONER BROWN: How does that drive the improvements that you see as necessary for that grid?

MR. CALDWELL: Well, I think if you're talking about driving improvements, I would agree with what other people said that CRRs are never going to be the sole mechanism that we get for upgrading the grids. We're not going to have some Ouija Board that says well, gee, our CRR balancing account is $250 million, well now we don't have to have any proceedings to talk about cost benefits of new transmission enhancements, all we've got to do is look and see what those -- I think that's total hoops, or something.

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And so it's an indicator but there is never going to be out of work for people to watch this process on behalf of the public, in the public interest, to be able to make some changes. These Commissions, neither of them, are going to ever go out of business. Anybody who thought they were in the old days --

COMMISSIONER BROWN: Well, I've always prayed Mr. Schwarzenegger would put me out of business.

(Laughter.)

MR. CALDWELL: Maybe there is something about having 27 different Commissioners looking at one little basket but, you know, let's just keep in mind here what's really going on. There's going to be a need to continue to learn, to continue to adapt, to continue to get better. But we've gotta get on that process of getting into financial rights. Because if we try to take a network and carve up a network into physical individual rights, the inevitable result is that network will be significantly underutilized.

And it is now and it's getting worse. And this network is the public good, is the public interest. This transmission network is what drives this whole thing. And unless we focus on getting that utilization better, we're going to lose.

PRESIDENT PEEVEY: So you're an enthusiastic supporter of lockout and zone control area?

(Laughter.)

MR. CALDWELL: I'm sorry, I must have misspoke, if that's what you're talking about.

COMMISSIONER BROWN: No, I misunderstood you.

COMMISSIONER LYNCH: Mr. Caldwell, are you really talking about the muni reservations on the system or are you talking in a broader sense, in terms of the energy used?

MR. CALDWELL: I'm talking in a broader sense. And I think one of the problems we have is I don't see -- you know, the munis, let's face it, they are 30% of the load in this state and they're 50% of the transmission grid. I don't see anybody up there at that table up there that even purports to be someone who is on behalf of them. I think that's a real problem. And I sympathize with munis in that vein. We tend to get too PUC-specific, too FERC-specific, and we don't have those people at the table as equal partners. And in this state, as I say, 50% of the book value of transmission systems is publicly owned.

On the other hand, having said that, I think for the publics to say their reaction to that is to go off and, you know, pick up their ball and go home and do it themselves is anti-social.

(Laughter.)

And somehow we either have to incentivize them to join, make it easy for them to join, or we're going to have to get out the stick and do it or we're not going to get there.

COMMISSIONER MASSEY: I have a question. It seems to me that Mr. Auclair's vision of the way -- of who owns the CRRs is dramatically different from anyone else on this panel. And I'd like the rest of you to comment on it.

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I had thought, Mr. Auclair, that we wanted load-serving entities to own CRRs as a hedge. And you seem to be saying that we should have a policy that makes that impossible, because that gives them market power. And I'm interested in that point of view, but I just wanted others to comment on it. I'll have your position line.

MR. AUCLAIR: Commissioner Massey, please allow me to just clarify. I agree 100% that the revenue rights, the pot of money, belongs to the load and to those who have paid for the transmission system -- if they paid for the embedded costs, they shouldn't have to pay twice. That's number one point.

The second point I'm arguing for bifurcating, separate the pot of congestion revenues from the financial instrument itself, like PJM, as an example. So just as a clarification.

COMMISSIONER BROWN: You're also arguing for core and non-core allocations. I heard you.

MR. AUCLAIR: Given that the CRR allocation is an incentive.

MR. NUNNALLY: Commissioner Massey, I'll take a stab at responding to that. I think -- in my view, I don't think there's a big difference, the way I understand the proposal from the ISO, as Lorenzo said, CRRs are portable, and as load moves from one LSE to another LSE, they'll go with it. I view the LSE as basically the steward acting on behalf of its customers to manage the costs of delivering power and procuring power for those customers. CRRs become a vehicle to hedge part of the costs associated with providing that service. So it's not a question in my mind of ownership being the LSEs, the LSE is a steward for the customer and uses those CRRs to provide the service. If that customer moves to a different LSE, those CRRs move with them.

COMMISSIONER MASSEY: Mr. Auclair, is that your position as well?

MR. AUCLAIR: Indeed, we need rules, clearly established rules to allow, yes, the CRR to move with the load automatically. And one fear I've had is it's always in the implementation detail, for example, that the auction is done on an annual basis. Then the immediate question is well, if there's certain load once you change suppliers what happens in the interim? Can the CRR travel immediately on day two, for example, or does it have to wait -- does the load have to wait until the subsequent auction before it can bring its CRRs with it?

COMMISSIONER MASSEY: I think I misunderstood your position somewhat.

COMMISSIONER BROWNELL: I just need to do a little more reconciling.

Jim, if I heard you correctly, what you said is that we do need to move to a system of financial rights in order to optimize the grid and whatever way we get there is likely to not reflect changing realities.

So that we need a system, as seems to be suggested by you, Lorenzo, of some flexibility to correct along the way.

Is that -- am I interpreting what you said correctly?

MR. KRISTOV: Well, in terms of the allocation of rights, by virtue of having a monthly auction, as there are changes that require new contracts being formed -- a different distribution at a load-serving entity might mean changes in the volume of load that it's serving, changes in seasonal pattern. That was the rationale behind having the monthly allocation process in addition to the annual.

MR. CALDWELL: You know, I guess you were more articulate than I was at saying what I was saying; I think, you know, that's exactly right. I guess I would add to that that I get nervous when we talk about monthly auctions because what that's beginning to sound like -- and, you know, there are ways around this and we can do this. But that's beginning to sound like the days when everything was on the spot market.

Because if what we're saying is that a congestion revenue right is only good for a month then almost by definition -- it's not totally true, but it begins to sound a whole lot like no long-term contract can be really hedged and really be fixed for more than a month if a month later I have to worry about whether I'm going to be able to retain that right.

And, you know, I mean we gloss over that when we're speaking about all these things and all these little levers and all these little mechanisms to keep flexibility and innovation alive -- which, as we agree, is key. But again I think the metric we need to watch for is is this the way that we need to be able to make sure that someone can do a long-term contract or else this whole exercise makes no sense out of these CRR auctions. So thinking about these theoretical flexibilities gives us a problem unless we keep our eye on the ball.

MR. NUNNALLY: Commissioner Brownell, I think just one of the other flexibilities that's built into this as I understand really focuses on the tension between Phil's requirement or desire for something that's transferable quickly and Jim's requirement and mine as well that there be more protection for longer-term commitments is the fact that these CRRs are not allocated 100% for a year or 100% by month. There's some proportioning of those CRRs -- some being annual CRRs, some being monthly CRRs -- so that you try to span the flexibility requirements. If anything, I think there is a greater need to consider even longer than a year CRRs as we move towards longer and longer commitments to resources in order to avoid the volatility that we've seen in the past.

So, if anything, I would say there are needs for some longer-term commitments, but in any case there's a need for a parsing of those CRRs between short-term and long-term to deal with both ends of these spectrums.

COMMISSIONER BROWNELL: Thank you.

Derek?

MR. BANDERA: I think what -- what I understood what you were saying about the auction versus allocation method held true. What you were saying for the auction method that you see, was that essentially a load-serving entity in the sense the way the revenues -- that he could check a box if the auction procedures say I'm not willing to sell my CRR in the auction and basically bid a large amount of money and not have to risk giving it up in the auction procedure, because he gets the revenues back. So that the auction process itself doesn't risk an LSE who doesn't want to lose his CRR from losing it because he has the opportunity of basically outbidding any other participant. Is that correct?

MR. KRISTOV: Yes, in concept that's the basic idea, that a party who's bidding in a market and is getting a share of that market's revenues clearly is going to have different bidding behavior from someone who is actually spending money to buy what they're bidding for. So that does provide an equalizer. That being said, I think it's an additional step of complication: who has formal load-serving entities to go through that on day one.

COMMISSIONER BROWNELL: Maybe our Staff can speak a little bit to this in more -- than perhaps you can, because you've obviously done some homework here. It strikes me that as the other markets have evolved, both in this country and in other countries, they have actually done some on-going assessments and, to some extent, changed the way -- I think everybody started with an allocation added. I think everybody has kind of added some kind of an auction feature in future years. But maybe you could speak to that, because I think that is a concern that people have on an on-going basis.

I also want to add, Jim, I agree with you completely that getting the metrics right and really monitoring what is going on in a far more sophisticated way even than we do today, and we're a whole lot better than we were two years ago, is critically important to make it all work.

MR. KRISTOV: Thanks for the opportunity to follow-up, Commissioner.

We talked with the eastern ISOs about this and New York, I believe, started with an auction process and many of the staff people there felt that that was a complicated way to start, even though they've gotten it to work acceptably. Now we're not proposing allocation and auction to the exclusion of each other, that there's an allocation step whereby those entities with an entitlement to rights -- those being the load-serving entities as stewards, as Ron Nunnally put it -- where the loads get their allocation. Subsequent to that, though, there is an auction process in which any party can bid for rights. So we're not excluding that auction, we're simply doing the first round to make sure that the loads are taken care of.

Similarly, in the time horizon question, Ron has also captured quite correctly what our intention is, that there's a substantial share that's allocated as an annual right and, in fact, we have a rolling proposal where you can buy rights for next year and the year after or you can get allocated rights for next year and the year after, so at least you would have two years certainty. And then the monthly allocation and auction process is really a true-up:

how do we need to adjust to account for seasonal factors, to account for load moving from one load-serving entity as load growth, et cetera.

We have had a number of parties and we agree that there are valid reasons to have longer-term rights issued but the overwhelming comments that we received were Don't do that on day one. Start -- because we don't know very much about how this is going to work, start with a shorter-term allocation and then think about -- a few years from now, after we gain some experience -- going to a longer term estimate, a 5-year or 10-year right.

MR. CALDWELL: Saying to me that I have a one-year pitch on what is a significant cost I think is a non-start. I mean, I think we'll be right back into a suit again. I mean, I think we're totally -- if what we're trying and say and what we're trying to do is to build in the ability to go out 20 years, which is I think what we're trying to say, then we've got to have a place for 20 year certainty of a contract. And I don't see that that's wrong, that that inhibits any kind of flexibility or that that inhibits any kind of adherence to market principles or innovation or all of that.

But to say that Well, gee, we're doing this stuff long-term, I'll give you certainty for a year. I mean, no one on the other side of the power purchase agreement with me is going to take this. That's just a non-start.

MR. CANNON: Susan?

COMMISSIONER KENNEDY: This is for any of the panelists: Does anyone think that the current statutory limitations on direct access impacts in any way the development of an effective and fair CRR market and how would the existing direct access customers be treated in an allocation method?

MR. KRISTOV: To your second question first, the allocation method, because it is based on the entitlement going to the loads themselves, then direct access providers would also get allocations of CRRs for the loads that they serve, just as the investor-owned utilities and municipals.

COMMISSIONER KENNEDY: So, to my first question, is the statutory limitation pretty irrelevant in the scheme whether or not --

MR. KRISTOV: In terms of an efficient allocation from the ISOs point of view, I think it doesn't matter who the entity is that actually -- that the load is served by, looking purely at the CRR process.

MR. NUNNALLY: Commissioner, that would be my assessment as well. Because I think with the flexibility that allocating this annually, with true-ups monthly, you can deal with changes over time in load responsibility. So I think that that's not a bear.

MR. KRISTOV: And I would add to that that if the state decides it wants to broaden direct access and make it easier for customers to choose alternative suppliers, the CRR proposal we're offering doesn't in any way inhibit that.

It would be compatible with however you go.

MR. PERLMAN: Can I address the long-term issue?

Would the establishment of a few trading hubs as a delivery location, where congestion is averaged over multiple buses like it is in some of the Eastern markets, reduced the concern with respect to the ability to enter into long-term commitments?

MR. CALDWELL: I think there's a variety of mechanisms, that being certainly one, you know, that we use that are tried and true and all kinds of other commodity markets, if you will, that have physical trades going on in the short-term and spot markets and then secondary markets or derivative markets that take care of the long-term. There's a thousand ways to do it. I just think that we have to make sure that our eye is on the ball, that that's the objective.  The objective isn't to create a spot market that works, only to the extent that that spot market is essential in order to have a longer-term market. So I mean we've got to have the flexibility that the spot market gives, for energy, for CRRs, there has to be a liquid spot market.

It has to be a liquid spot market. But as soon as we focus the exclusion of everything else on that liquid spot market, then we run into the problems that we have.

And so -- we just have to keep our eye on the ball. And I think there's going to be continued need to continue to think of better ways of doing it, but we have to get to that idea that that's really what we're doing, is just that we're allocating these revenues, the financial rights, as opposed to the physical property rights.

That we have to get over because we'll never get there from here as long as we try to divvy up what is not capable of being torn apart.

If Waco wants to run its own grid then it ought to run its own grid period. And ought not to have access to the grid here. Then we'll see how they like being a foreigner.

(Laughter.)

MR. CALDWELL: And I'm not trying to pick on somebody but I think we just have to -- call it the way it is. This is a common grid, we're in this damn thing together. And there's significant benefits to us all working together in this one box of using this common grid.

And if we can't somehow be adult about it and figure out how to do that then we've got a real problem. And we aren't going to fix it by some technical conference or some new tweak -- Amendment 47, to the tariff.

CHAIRMAN WOOD: We're in the 50s now.

MR. CALDWELL: That's right, we are.

(Laughter.)

MR. AUCLAIR: May I ask a quick question?

Jim, do you think having any such a liquid CRR market will enhance us some in here?

MR. CALDWELL: That's essential. In the long run. I think maybe we have a little bit of time to get there but I think that's an essential element is the liquid CRR market. And -- Chairman Massey, Commissioner Massey, said that maybe we could all disagree with you -- I don't disagree with your initial proposition that the LSEs themselves, or to put it another way, run on shareholders -- they don't own those CRRs. I don't think there's a question about that.

The only reason why they've been -- given the opportunity to on behalf of somebody else to use those -- is because there is folks like us sitting up here who have an ongoing ability to make sure that that stewardship is done properly.

Because they are not the rights of the shareholders of the LSEs.

CHAIRMAN WOOD: Lorenzo?

MR. BARDEN: I'd like to ask a follow up question on what Chairman Wood had brought up before about the CRR allocation and implementation of the software, and I was wondering -- is there any relationship between CRRs are allocated and the software implementation for the nodal system or are they separate issues and can be dealt separately or does one need to be solved before the other can move forward?

MR. KRISTOF: They can be solved separately. Essentially, the software engine that we would procure would have flexibility to deal with a variety of site allocation rules.

For example,when I responded to Ron Nunnally's question about the objective function, the fact that you don't put bids in itself allows a neutral allocation without respect to economics to load serve the end of each other's entitlement. That's one approach.

But then you can hook this then and you can run an auction using the same software and it will give you the right answers.

So they're really independent and we can go ahead and start using software that has the flexibility for the CRR process and then develop the allocation rules in a parallel fashion.

MR. BARDEN: So this is one of the things that needs to be decided today in order to move forward on the implementation?

MR. KRISTOF: The allocation rule of the CRRs.

MR. CANNON: Let me follow up a little bit on that. In terms of the time line that Lorenzo shared earlier, where does the unbiddable process begin. I'm wondering where the CRR -- I recognize how CRRs get allocated and ultimately auctioned and development of secondary markets -- all that sounds suitable as an evolutionary process, but how do we get these things up and running in a way that they support the MD O2 and the market redesign by the new time lines in 2005?

Is there a sort of a -- where do they fit in to the time line that Lorenzo shared earlier?

MR. KRISTOF: In terms of the CRR project and how it fits in, if we reason backwards from tariff language, I sort of -- if you noted on Spencer's chart, we have submission of tariff language right around the end of '04.

It all needs to be worked out by then.

So what we're envisioning is, over the next I'll say four to six to eight months -- and it's already started, a process of CRR studies, that is the next round of studies that is starting to build the capability to do the economic aspect of CRR evaluation. We'll be doing iterations of that over coming months through this winter and spring, and in parallel, having talks with the EUC and with stakeholders on how to formulate the allocation rules so that, if I'm viewing it by late in the spring, we'll be in a position with alive and creditable data from studies, a wide preliminary evaluation of what the options are and what everybody's parties are concerned, to start constructing what those rules are so that we're ready to have them well laid out in the tariff filing by the end of the year.

MR. CANNON: Are there any steps -- I'm just trying to think how that gets vetted and CPUC gets comfortable, how a participant gets comfortable, FERC gets comfortable -- with how the process is worked and whether the allocation is workable or not? Are there, we'll see intermediate steps or things that would be brought to the Commission for approval or some kind of a regulatory look-see -- does this look like it works, does it look like its got support from our participants for the necessary regulators?

MR. PEEREY: Maybe Sean could -- Sean Gallagher, could step in here and answer a portion of that question, Lorenzo, if that's all right with you.

MR. GALLAGHER: I could probably answer the question more broadly but I think it's our intent to work at the staff level with the ISO over the coming months as they prepare the studies that Lorenzo has described. We're going to do a lot of work to try to ensure that before they go too far down the road implementing those studies that there is a level of consensus not just within the PUC but among the market in general that the ISO is actually putting the right inputs into the study so that when the ISO comes up with an outbreak it's going to be something that most people can agree is valuable to inform their decision making.

But we're going to do a lot of that at the staff level, we're going to keep our Commissioners informed and my understanding is the ISO is committed to working not only with us but with the different participants as well and they've already started to do that.

MR. KRISTOF:  And I would add to what Sean said the fact that we are continuing to provide monthly reports to FERC on our progress on MD 02 implementation and we will be providing updates on the CRR effort in that context as well, in addition to recognizing in the Commission's recent order that we need to have our initial allocation laid out in the tariff language plus a preliminary preview of that information, roughly 90 days to filing tariff language.

So we see those as milestones and then the monthly report as a way of charting our course towards that.

Okay?

MR. AUCLAIR:  If we could, I would like to recommend in the last 30 second if possible, first essentially to bifurcate the revenue rights to upend -- you said you create option revenue rights and FERC admission rights and essentially to phase in the implementation of FERC admission rights for sales over a four year period to allow the development of liquid FTRs that are necessary for successful long term contracting in -- projects.

So my hope is that this proposal here stands at an early transition.

MR. CALDWELL: I guess I would only add to that that no one in this room can mandate the liquid market.

(Laughter.)

MR. CALDWELL: The liquid market is of itself. It is not -- it is a result of confidence and faith of the market participants that they trust that market, that's what makes it work as a result. And I don't think waiting for a liquid market is going to get us a liquid market but, having said that, we do have to get there and I think that -- I'm for whatever's next on the CRR allocation. And I don't think it matters to me -- Kirshoff's laws, and that state estimator and that AC power flow model which is optimizing the unit commitment of the current -- it doesn't check for the tariff before it says which way the electrons go.

We've got to get the physics right, okay? And then if we got this pot of money and rights that we're talking about, then we can argue for a long time about who owns that, whoever it is, and who will be doing it.

But let's get the physics right first. Let's get the software that says which way -- optimizing the utilization of this very, very important public asset which is the grid. Let's get it back up now.

MR. CANNON: We are at the noon hour so I would like to thank this panel especially their questions, and I'd like you to stick around for the next panel.

(Applause.)

(A recess was taken.)

(Back on the record.)

CHAIRMAN WOOD: Shall we go back on the record? Back on the record. Shelton?

MR. CANNON: Our second panel today will be dealing with what -- is talked about in terms of the first panel but what we're going to try to do now is some of the transitional issues associated with what to do with visiting contracts and how do we convert them to come on to this new market design.

We have with us for this panel Brian Theaker, who is Director of Regulatory Affairs for the California Independent System Operators, we have Steven Schleimer, Director of Marketing and Regulatory Affairs or the CalPine Corporation. We have Thomas Hodeson, Marketing Vice President of Goldman-Sachs, Pete Garris, Deputy Director of the California Energy Resources Scheduling Division with the

California Department of Water Resources, Ted Braun, who is with Braun Blazinger, representing California Municipal Utilities Association and last, but not least, Stephen Metague, who is Director of Electric Transmission Rates for PG&E.

Welcome all and if we could begin with Mr. Theaker?

MR. THEAKER: Mr. Cannon, thank you, Chairman Wood, President Peevey, Commissioners, good afternoon. Thank you for the opportunity to speak before you today.

The transitional issues around existing contracts have not yet been resolved and not easily resolved, but leaving them unresolved or trying to move to a new market paradigm will continue to leave an open wound in market design.

The parties need to resolve them and perhaps will need some impetus to do so before the Commission rules and need to decide for them.

End-congestion is a real problem with real costs.

The parties know that the non-uniform time lines currently in play in the ISO markets in regard to these indices creates a problem that must be resolved. Beyond that it is axiomatic that, for parties to gain true benefit in the competitive markets those markets must have uniform terms.

The ISO's core interest in resolving this, the

ETC's problems, the transitional contract with these problems, are these -- first, to ensure that the agreement is used fully as possible in the forward markets as far ahead in real time as possible. That's of course a longstanding practice of setting the system up a day in advance for real-time market and the deviations market, and not an opportunity market.

Second, to get the ISO out of the business of administering a myriad of transmission contracts it did not negotiate nor to which it is party, that has non uniform terms. An ISO should be about offering uniform service, yet the only way the ISO could do this in the early years was to make simplified assumptions regarding those contracts where they provided some part of the windfall that they had not been able to negotiate.

Taking uniform service, like uniform service is also what the commission contemplated when -- standard mercantile -- in that the Commission said that the ITC should provide uniform service and the PTOs would use that service to fulfill the terms of their existing contract. ISO charges would roll up to the PTOs and the PTOs would be provided to CRRs to hedge any congestion purposes.

The ISO in MD-02 design offered a similar proposal. First, the PTO is responsible for administering the contract. Second ETCs would have bid priorities. Any unused ECT capacity not scheduled a day ahead would become available to the market for use to ensure that the grid is fully utilized as far forward in advance as possible. Any hour ahead ETC changes would be accommodated as long as they don't affect the day ahead schedule.

To the extent that they do, they would be rolled along with real time changes into redispatch in the real time market. All charges would roll up to the PTO and then finally the ISO would support the PTO being able to recover those costs in the regular interval.

The ISO proposal was intended to honor the rights of the existing contracts and still allow the grid to be totally utilized in real time as much as possible -- or in the forward market, excuse me -- as much as possible. We acknowledge that there is some details that remain to be decided on this issue including cost allocation and we look forward to working with the parties for conditions to resolve these -- some parties have suggested implementing a non FERC transmission service as a solution to this problem.

From the ISO standpoint this feature adds complexity, adds costs and, because it adds cost, it raises a host of cost allocation issues.

The ISO experience with a non FERC accountable process has been that the parties in California could not come to terms on implementing such a service in its own markets let alone in nominal markets.

Furthermore, a non FERC product -- a separate non FERC product would create a quote "opportunity market" which can create incentives which interfere with the robust participation in the day ahead market.

For the ISO it comes down to this core issue -- is it better to make limited use of grid facilities by ensuring that they are fully utilized in the day ahead market to the extent possible or to intentionally pull the grid to under utilize and accommodate options that may or may not be exercised in real time.

We believe that the proposal submitted in MD 02 strikes a balance. First it eliminates a real problem, phantom congestion, by making ore of the grid available for use in the day ahead market.

Second it honors in terms of existing contracts by allowing priority in the day ahead and then to redispatch in real time and then third, it better realigns the interests of the parties so that the parties who negotiate the contracts are responsible for administering them, leaving the ISO free to focus on administering the uniform service.

Regarding the second issue, on salvage choice contracts, we acknowledge that this too is an open and contentious issue. It's not equitable where sellers can profit merely from a change in pricing paradigm nor is it equitable that a market design can be compromise through a desire to maintain existing contracts.

The ISO's position in regard to this issue is this. We believe that the problem is best solved through a renegotiation of terms that would specify six delivery points from which then the ISO could allocate CRRs who hedge those deliveries.

The other ISOs who have faced this problem have resolved the problem this way, to renegotiate and collaborate. We have expressed a willingness to continue working with the parties to resolve this but should no consensus emerge from California, and let's hope that one does break the six year trend that the Commission must act to decide this issue.

COMMISSIONER BROWN: We get along, we're all Democrats in here, right?

(Laughter.)

MR. THEAKER: Thank you for the time.

(Laughter.)

MR. SCHLEIMER: Good morning. My name is Steve Schleimer and I am Director of Markets and Regulatory Affairs for California Corporation and I am very happy to be speaking this morning --

I focus my comments on three areas of --

transitional issues. First is how the ISO's MD 02 proposal may appear with existing contract rights as result of the movement of the best offer to real time a day ahead.

The second issue is how the so-called sellers choice contracts need to fit into the LMP world.

CalPine has many of these contracts both with DWR state agencies as well as with other counterparts so obviously we're very interested in the outcome.

Finally I would like to address quickly how developers such as CalPine that are still planning on constructing new infrastructure in California and we still have 3,000 megawatts that we're planning on moving forward with and are potentially putting ourselves in a box related to market, local market time mitigation mechanism and some ideas on how to solve that. And I know there's a panel on that a little later and so I will touch on that quickly.

First I just want to take a step back and we say that from my perspective, from CalPine's perspective, to see the market transact and transmission access in California is not bad.

You know, in a lot of places across the country we can't even get our generators interconnected much less transmit the power from point A to point B.

In California if we want to transmit power from point A to point B, we can do that and I think that's absolutely what this is all about and I think to some extent these other issues are very important but they are second order.

I'd like to move to my first point. When ISO proposed to move the must offer from real time to day ahead, according to the ISO proposal any generator must offer all it's capacity into the day ahead market that's on the schedule. The proposal basically requires providing the capacity to do this with no compensation.

More importantly for us, we have a lot of existing contracts that have what's called "intra-day scheduling rights," and specifically, with the DWR, we have contracts that say they can call us -- you know, it's 12:30 now, DWR can call us to generate at 1:30 or 2:30, and to have a proposal where we had to bid the generation where we were going to meet those requirements with, you know, yesterday, doesn't seem to make sense and it doesn't seem to me like we're going to be able to meet our contractual commitments.

So FERC has solved some of this problem by giving sellers a choice leaving the day ahead or a real time must offer obligation to help solve this problem.

I'd recommend that they take one step further. One of the reasons why they see a reliance on the real time must offer is that there is a lot of revenue showing up in real time and I would suggest that perhaps we need to look at the incentives that load serving entities have in having some of it showing up in real time.

Right now there's a lot of penalties put on under scheduling and over scheduling whereas on the load sides there are no such penalties and I would suggest that prior to getting to a capacity market which I think is built with some exclusions, that we need to look at that.

On the second item, that's how to deal with the so-called seller's choice contracts and these are contracts like for example like CalPine we have a couple of contracts written in clauses which say delivery point is and can be an MP 15.

Now the question is, when MP 15 is broken up into hundreds of nodes, what does that mean and how do you fit that into the new markets out there.

The resolution of this seems pretty straightforward to me and that is what does the contract say is going to happen to the extent that their market changes.

The FERC noted in its decision some contracts already contemplate these changes while others do not.

It seems to me that bilateral negotiations between the parties are the only way these issues can be resolved. We don't need to look to additional litigation on that.

That being said, there may be a role for the ISO to play in determining options of services that could facilitate implementing these changes and the ISO has laid out a couple of them in their MD02 proposal. They gave word there may be others.

What we would like to ask FERC is to request that the discussion of these alternatives be opened up. So far they don't have any say in participation of any steps that have been pretty much everyone except the sellers that are counterparties. Typically the discussion is fundamentally how does the process go from zonal to nodal. We think it's only fair that everyone can stand at the table and try to figure it out.

Finally and just quickly, another transitional issue. As I say, Calpine is stuck with 1000 megawatts on both sides of the California-Oregon border. The CPUC is making significant progress.

But another concern is to the extent that we build these plants and bring them on line in a world where there is significant local market power mitigation, are we building ourselves into a box?

And that is, we haven't built these plants yet but once we've built the plants they become subject to significant local market power mitigation.

I think that the answers that we come up with for local market power mitigation -- and I think our next report needs to address local market power mitigation in new areas.

And, you know, we look forward to working with the Commission to develop some of those alternatives. I know in the order there was an additional technical conference that was to focus in on this. I'd be interested in any questions or comments.

MR. CANNON: Thank you. Mr. Hoatson.

MR. HOATSON: Thank you, Mr. Cannon. Thank you to the Commissioners. On behalf of Goldman Sachs, I appreciate the opportunity to be here today, to discuss some very important issues. I'm Tom Hoatson, a vice president of fixed income, currency and commodities division within Goldman Sachs. THis is a division that has been trading power for several years now, first as a counterparty with Constellation, and since January of 2001, as part of our J. Aron trading subsidiary where we also trade metals, a few other products, natural gas, as I said, since January of 2001. We have recently also started a business where we on October 15 we closed our first deal of the power plant located in New Jersey that's tied into both New York and PJM. We also recently announced the purchase of CoGentrics, which is a privately held developer in Charlotte, North Carolina, and most recently we entered the California market with the acquisition of its CWR contract several weeks ago.

I would like to commend the ISO for what I think is a wonderful job on the proposal. I think it was thoroughly researched, thoroughly thought out. I think they went to the other markets and tried to take the best of those markets, they looked at what's been working in those markets and tried to allow flexibility, tried to correct those problems.

It is lacking in the details. I think everyone knows that but I think it's a wonderful framework for going forward.

I'd just like to give the Wall Street perspective on the issues, the main issues, at hand as well as kind of override the process that we are in.

Probably the most important thing to Wall Street is certainty. We need certainty whether it's in bilateral contracts that terms would be honored, the conditions and terms will be honored for the term of that contract, that the contract will not be abrogated. I hate to use the term, 'sanctity of contracts.' I think everyone in this room has heard that for many years now.

I'd just like to leave you with a couple other thoughts as we go forward with this from Wall Street's perspective. Wall Street prefers options over obligations wherever we can do that and something we heard a lot about in previous discussions, Wall Street much prefers auctions over allocations.

I sympathize with the ISO in their CR proposal going forward, that the first one tried as allocations. I think we can support that provided there is a commitment and this goes to the certainty issue that, down the road they will start looking at the auction process and that is consistent with the way PJM entered the market.

I think that has worked well for PJM but there has to be some commitments within, going forward with proposals that eventually the auction would be in place.

Thank you.

MR. CANNON: Thank you.

Mr. Garris?

MR. GARRIS: Thank you.

Chairman Wood, friends and Commissioners thank you for giving me the opportunity to speak.

Let me start by saying that the Department of Water Resources has two halves with respect to the energy group. The first one is CERS, that's the division that was created by the Power Bureau during the emergency and is the counterparty if you will with a significant number of long-term bilateral contracts.

The second is the State Water Project, as the operator of the aqueducts, reservoirs, pumping plants power plants and takes on the State Water Project itself.

Internally, they function independently of one another. Their authority comes from separate sections of the water code and they're separately funded, one through the Electric Power Fund and one through the Water Resources Development Fund.

The common ground for the Department of Water Resources whether it's SARS or the State Water Project is that they're both dedicated to the physical delivery of electrical energy and/or water.

And a couple of comments on the market design and NETCs. Internally at CERS we've been focused primarily on the cost and the impacts of the proposed market design, in particular, locational marginal pricing and while we're doing the study and the analysis and it's still a work in progress, some things have become apparent to us.

The one is the proposed LMP based settlements process is going to impact all bilateral contracts that were entered into. Basically a zonal model of grid operations and billing and settlements and, to the extent that they have floating point or seller's choice delivery we do agree that a full network model is a superior approach to the current network model. This should in fact give significant improvements to grid reliability.

The preliminary CERS analysis shows a significant cost is going to occur under the LMP settlement process.

Again, of course, we're still doing this, analyzing our own work internally but the costs are significant potentially in the billions of dollars over a seven year period.

Another thing that came to light during our analysis is that the cost appears to be much greater in Southern California than Northern California. Again,maybe there's additional information or discussion that can occur to see if the ISO and other folks who have done an analysis agree with us.

When we did our studies the results were done by assuming normal market conditions. We didn't stress the market and we think we didn't include any gaming. As a suggestion on ways to maybe bridge the gap from where we are now, the current zonal model, to an LMP model or whatever future model is ultimately arrived at, we have a couple of suggestions and maybe when the panel has further discussions we'll get into them, but one is the trading hubs that we're suggested at least by previous speakers and a second methodology is maybe doing some thing along the lines of a tagging process or with respect to the way the ISO currently manages constrained resources, tagging those contracts that are existing contracts and essentially accounting for them in the model but then backing then out of the financial settlements so that neither the seller nor the buyer achieve an advantage or a disadvantage during the process.

As part of our recommendation we propose that no buyer or no seller gets a clear advantage or disadvantage for something that they committed to in the past and is especially an ongoing commitment that is going to be subject to changes in the market.

Something else that became apparent to us, while we're able to determine some of the cost associated with the LMP design, we're not able to measure them against the benefits and I guess what I suggest is that the benefits also be defined and measured against the cost and the changes that are going to be necessary going forward.

A couple of quick comments on ETCs.  As most of the folks know I work on the energy side primarily with CERS and in our discussions with State Water Project folks, they indicate to me that ETCs, the discussion of how to incorporate the existing transmission contracts in the new model are going to require additional discussion and additional information.

The current proposal doesn't really provide the type of transmission product that you really need to operate a dedicated facility such as the State Water Project.  CERS on the other hand has no ETCs and doesn't have that particular issue on its plate.

As I understand it, other ISOs have dealt with the issue of ETCs and in some cases have granted part of the

ETC rights into their market design. And with respect to the Water Project, the significance in my mind is that 22 million Californians get all or part of their water from that project on an annual basis and, as a final remark, I suggest that we all take the lessons that we've learned and apply them to the process as we go forward.

Thank you.

CHAIRMAN WOOD: Mr. Braun?

MR. BRAUN: Thank you, Chairman Wood, FERC and PUC Commissioners, thank you for the opportunity to be here.

First of all, I'd like to set the record straight. Municipals are not anti-social.

(Laughter.)

MR. BRAUN: And given the late hour, and before lunch and to prove that we're not anti-social GOP we'll freeze for everybody. And we'll share some peanuts.

(Laughter.)

COMMISSIONER BROWNELL: You get a free CRR for that one.

(Laughter.)

MR. BRAUN: First of all, I'd like to emphasize that the municipal community appreciates the emphasis on problem solving. We try to deal with these things in the practical and not in the theoretical -- and I'm encouraged actually at this juncture. I hesitate to make this admission against interests but I've been involved in the -- with ETCs since before ISOs started up and so has another gentleman on this panel, to my left.

And I think we'd both be surprised to be here at this juncture still discussing this issue.

But I am encouraged by two things, one, the Commission's order, which I think is preparing to take a fresh look at both the operational and the financial impact of ETCs as well as I think that the PTOs and the existing contract transmission customers are in different positions now than they were in 1996 and 1997, vis-a-vis this issue.

So I am encouraged despite the lack of progress that we've made to date.

As is clear from the pleadings from this proceeding, we did not believe that the municipal community have got ISO's proposal on our existing contract. It fundamentally takes and changes the character of the service from a reservation in forward markets. It allocates the use of right under those contracts to other market purchase events and just as significantly it makes the contract right holder the price taker when they exercise the rights that are under the contract and are paid for at a set price.

So we have some serious discussion to be had on this issue but without dwelling on our objections to the ISO proposal I think I'd like a few take-aways from the

Commission on this technical conference on this issue.

One, we think the white paper and the principles that are enumerated in the white paper are the right ones to solve this issue regarding the hold harmless for existing rights whether those be implicit or explicit, a real need and recognition that native load customers require protection during the transition to a pooled network model.

These are the guideposts that we would support whether you're dealing with the native load that's not covered by explicit contracts or whether you're dealing with an ETC right as we seem to be discussing it today.

Two, don't prescribe surgery to cure the common cold. Spence laid out a time line of 2005 to implement a full network model and on the rule of thumb of half as much and twice as far. We don't know.

But that 2005 date is beyond the expiration of significant existing contracts in some of the more complex integration agreements that are on the books right now. Does that mean the ETCs will go away after 2004? No.

But the number of them and the complexity of them will diminish. We should be looking forward in trying to assess what those grids will look like at that time rather than trying to assess what may or may not have been the impact of ETCs looking backwards.

Third -- I think the Commission would do well to look at this as a seams issue and a regional issue and not a California issue. There's reasons why my clients, municipals, spent billions of dollars on transmission and generation. They go to the inner tie points in California mostly.

The statistic that was raised by Mr. Caldwell about 50 percent of the imp of the transmission, that is the import capacity into the state that's publicly held, both federally and otherwise.

Those rights are tied to prevailing regional practices regarding scheduling and there's a disconnect because the design elements of the MD 02 and the ISO now don't have the same priorities as in our neighboring regions. We need to look at a holistic approach that combines what we're trying to accomplish bringing those load, the generation home to serve load and the assessments that were made to look to a potential solution to this.

And with that there are I think, several alternatives, some of which have already been put forward. One, CMUA as well as Southern California Edison has held out the idea of a recallable transmission product that would create a non firm product for use of on unused capacity. It's true. There's been a lot of discussion about this and, to date, there has not been closure on this issue.

But again, we're looking forward. We're designing new software systems for California. We have changing circumstances with different contract rights. Those types of options ought to be explored before we take on lightly the idea of reformation of these contract terms, several of which have broken seal preventions.

Next, the Commission may have heard of an organization called WestTrans which now has 17 private and public transmission providers that have signed up and is going to be starting in OASIS for one stop hosting of excess transmission.

Now, it's going to span the entire West. You can see this as not the ultimate solution but I don't think we're here in the business of coming up with next year or so the ultimate solution on using the transmission grid.

If there is a way to sell excess transmission capability in the secondary markets we ought to be exploring it. We ought not to say there's a software obstacle. We ought not to say this is going to be administrative for the public transmission providers and private transmission providers that are looking at this OASIS site as a way to market at cost-based rates excess capacity. That ought to be seriously explored.

There are other options, changing scheduling time lines that make them closer to real-time that also would ameliorate the so-called phantom congestion problem and what similarly we urge as we go forward on this issue, we need to take a look at all these with a clean and blank slate with them all on an equal footing, examine the pros and cons from an administrative standpoint as well as an efficiency standpoint so we can avoid the Hobson's choice of looking at performing these longstanding and complex arrangements.

Thank you very much.

MR. CANNON: Thank you Donnie. Mr. Metague?

MR. METAGUE: Thank you, Commissioners.

I'm Steve Metague on behalf of PG&E. I would like to thank each and every one of you for assembling here today to talk about this very important issue of the wholesale market and market design in California.

PG&E has supported and continues to support reform of the market and the MD 02 proposal promises a well functioning wholesale market and with it the all-important benefit of reducing costly concerns.

Our work, as you already heard, some important details are still missing in the conceptual proposal that the Commission recently ruled on. But we remain hopeful that the details of MD 02 can be worked out and the promises can be delivered.

Today I will briefly comment on two important transmission issues. The first is existing wholesale transmission contracts and the second on the bilateral contracts you've mentioned earlier that the state entered into during the height of the energy crisis.

Let me first start with the existing transmission contracts. At the outset of the ISO's operation back in 1998, PG&E was providing about 4,200 megawatts of firm transmission service to municipal, state and federal agencies. And those contracts did not fit with the ones designed in 1998 in the market design.

And there are still issues that will again haunt us as we move into the MD 02 proposal and I'd like to talk about those.

First the issue of phantom congestion has been directly addressed by the MD 02 proposal and we're hopeful that that issue may be able to be solved through some of the techniques that Brian mentioned earlier.

However a second issue which I'm going to refer to as trapped costs is still with us and one of my concerns is that the MD 02 proposal may very well exacerbate that issue.

The current costs in our view are those costs that have been under continuous litigation at the FERC -- since I think 1998 and it's a question of who pays. And we've had strong arguments that beneficiaries of the new market should pay. We have heard arguments that holders of the contracts should pay for the new services they're enjoying.

But as yet the issue remains unresolved and for the investors in utilities hundreds of millions dollars are still unresolved in those issues.

In MB 02 our concern is that the costs of congestion, intra-zonal congestion, could now be layered into that total cold track cost. The question is going to be who's going to pay?

So with that, I would like to move on to the second issue that I wanted to mention, that of bilateral contracts, in that these paid contracts, there's some symmetry here that have been allocated to us and some 60 percent of those are in the so-called seller's choice contracts -- and it's those seller's choice contracts that cause us the greatest concern.

We are concerned that those contracts cannot be properly hedged. We are concerned that they offer opportunity for gaming and at the end of the day our most concern is that they could represent the transfer of wealth from delivered consumers to generators, which we don't think they deserve.

What are the solutions to all these problems? For the bilateral contracts we see that there is either a need to reform the contract or some modifications are needed to the current proposal relative to the treatment and the true balance and testing.

I was encouraged by Steve's Schleimer's remarks that he wants to come to the table and discuss those contracts. That's kind of important direct lobbying.

Relative to the existing transmission contracts, we have solutions that are currently under litigation at the FERC and I am not at liberty right now to discuss those issues -- but there is one point that Tony raised that I would like to pick up on and that is, to date, since 1998, nearly one-third of our existing transmission contracts and also customers with wholesale customers have either terminated or we've been able to resolve through negotiations some techniques that allow them to be better integrated into the marketplace.

Only 1/3rd more are going to be coming up for exploration within the next 14 months and PG&E will be making final arguments before the Federal Energy Regulatory Commission to terminate those contracts.

And we encourage the Commission join with us in making sure that those contracts do terminate at the end of their terms --

(Laughter.)

MR. METAGUE: -- and allow part of the transmission contract issue to be resolved.

In summary, we fully -- I, we fully support techniques that were raised by the Commission as they were two weeks ago in that we believe that collaboration is important. We want to see more details. We would look forward to such issues as how CRR allocations will be dealt with and we are also very interested in having I'll call it a 'dry run' before we go live. Let's find out before we jump into this marketplace at least try to learn what might be some of the trail abuse before we jump in with both feet.

Thank you. That concludes my remarks and thank you for listening to us.

MR. CANNON: Questions?

MR. SIMLER: Tony Braun throughout the three alternatives resolving the transmission times and changing the scheduling time on them closer to those times and I was hoping that the ISO and PG&E could respond to those.

MR. THEAKER: I can confirm there's a whole jar of peanuts there.

(Laughter.)

MR. LYNCH: Too much salt.

(Laughter.)

MR. THEAKER: First of all, Mr. Chairman, before i begin, I think I need to clarify something.

Commissioner Brown, I did not mean to imply by my comment on the six year stalemate that that was necessarily simply between the PUC and the FERC. I think that the State of California has found itself beyond its boundaries so I apologize if my clients find it even less.

The back -- issues, recallable transmission and on changing the scheduling time lines, the FERC again has heard that a third of the contracts have expired, a third more are set to expire. And so the idea that, given the difficulty that we experience to try to keep a consensus on again an RDS product in a zonal market with all the complexity and all the cost computation issues that went to them were very dubious in trying to create such a product again to accommodate a relatively diminished amount of rates that remain less following the expiration of these things.

If you have to do anything else, again, to get to where an ISO should be offering uniform service, you have to do it for one contract with 10 megawatts, you still have to build the same system that you could build for a 4,200 megawatt contract facility.

We are hopeful that a solution can be found outside of implementing of the cost of recallable transmission cover.

To the issue of changing the scheduling time lines moving them closer to real time, again, that's really moving the world in a different direction than the ISOs prefer to do it.

Again, the historical practice of power system operations has been let's set the system up today and get an advance and then let's only deal with real time deviations as they arise. Moving choices, moving options, moving schedules closer to real time allows the operators less time to deal with problems as they arise and so on both of those end-points I think we disagree with Tony and the direction he would pursue under his evolved position.

MR. METAGUE: I would just say as comment as well, that -- the concept of a recallable transmission service, to me, would need a lot more information I think before -- I would need really a lot more detail in order to react in a concrete way to that proposal.

But as a time line let me suggest that I think our experience has been that it's really doesn't work just the time lines out there.

And that's been the solution to phantom congestion wherever markets that the ISO closed, transmission is held for potential use by the -- community and in some cases it is abused and that seems to be very wasteful. So we believe that time lines need to be consolidated.

PRESIDENT PEEVEY: Rebuttal?

MR. BRAUN: I think I'll take this backwards as a point of clarification. It proposes a change of schedule of time lines precisely to consolidate them, to move everyone's scheduling time lines closer to real time so we can reduce the exposure to balanced energy so that you are able to make changes in loads and generation so that you have less energy in the real time market.

It seems to be precisely the direction which we've been trying to put California and it is absolutely consistent with prevailing practices in the rest of the West and is how the California grid was operated before the ISO started. The ISO does more schedules than the old control areas did. They operate a complex system, certainly more complex than the other control areas that preceded them, which I guess is part of our point.

But to simply dismiss this out of hand and to not fully explore the options in this regard, which would not only benefit the municipal community which is trying to integrate generation and load and reduce risk in the real time market and we should also benefit the rest of California consumers we believe. We think this is not simply an option that we have available to us.

We ought to be exploring it as far as the point that we couldn't do recallable transmission before, again, we're redoing the system in California. One of the debates over recallable transmission was that, who gets the revenue that's generated by the new use? We can get to the point where we're dividing up the pie of the fixed costs of the transmission system for that limited amount of capacity, I think we've made a lot of progress.

And when you see Edison and Schwartzenegger taking similar positions on this I think everyone ought to take notice.

(Laughter.)

COMMISSIONER LYNCH: I have a question for Mr. Garris. I have not been following the preliminary analysis that they did -- very closely but you mentioned it in a comment that your preliminary analysis is finding the cost to be significant in terms of I think what you said was LMP implementation. Do you have a stand on that and tell us what you're finding?

MR. GARRIS: That's correct. To the extent that you assume varying levels of energy can be scheduled by using a floating point or seller's choice point, we did our study, again, it's direct. It's internal and it's still preliminary but we did it over a seven year period and based on the varying amounts of energy that are used in the assumptions, it runs at a minimum in the one to two billion dollar range and in the extreme, if you assume somewhere around 5,000 or so megawatts and what I'm hearing now from Pete -- would suggest that we're fast approaching that. It's going to run in excess of $10 million.

COMMISSIONER LYNCH: Did you mention that you --

as due to FERC with a function mark up without rate --?

MR. GARRIS: That's correct.

COMMISSIONER BROWNELL: You know, it would be really helpful I think to all of us -- I feel very uncomfortable in that we've all been kind of victims of competing studies in the last couple of years. If we could get that study out and if we're going to talk about a draft I think it behooves us maybe to let some other including the ISO take a look at it.

It's hard to debate conclusions that clearly haven't been vetted to be honest with you. I appreciate the work you've done but this is a very awkward kind of discussion to be having when we really haven't a clue as to kind of how that study came about and what the assumptions are and certainly given the number of cost benefit studies we've seen in the last year we know that different studies can say different things.

MR. GARRIS: I agree and it's our intention to make this a public document as soon as we're comfortable with the methodologies that we used in our own assumptions we're currently in the process of essentially breaking it down and putting it back together internally. We're going to work with the other stage agencies and the investors and utilities share that information with them, let them assess our analysis, see how it, and in particular, the ISO, let them compare it to what we've done, see where the differences are if any and then we can have future discussions.

COMMISSIONER LYNCH: I would agree. I wasn't aware that you had already done that kind of analysis. But I do see that as underscores PG&E's point which is, we need to work out the kinks and maybe do some test runs and modeling before we go live.

CHAIRMAN WOOD: Since the congestion that is included in everybody's terms tonight and just can't tell where it is, these regs go down by a billion a year.

MR. GARRIS: Whose rates go down?

CHAIRMAN WOOD: These terms have been focused in Southern California, is that San Diego or is it SoCal?

MR. GARRIS: The focus of the study is on bilateral contracts in the zonal market that would in all likelihood allow for floating delivery points or seller's choice in the delivery points to the extent, and I'll use DWR as an example, to the extent that those contracts service load in California, the ratepayers associated with each one of the utilities that have had to contract energy allocated would pay the difference of those costs, the costs would then flow back to the providers of that energy.

CHAIRMAN WOOD: The seller's choice contract issue that came up in our order last week and we would kind of quite frankly cut in on the bid. Talk to me more about it. Because this was an issue in New England when they went to new market design and had that vestige of an old market design contract still around. How do you think that ought to be handled here in the California market when we move to the formal implementation of MD 02? What's the proper way to handle that?

MR. GARRIS: Well, I guess as I suggested earlier, the basic premise would be that nobody gains an advantage and nobody is disadvantaged. Now, I realize that something is going to shift but, to the extent that you can remain neutral in this transition process, I think that's a significant goal that should be attainable. We've had a lot of really bright people working very hard and they've come up with some very good solutions to the existing problems.

Two suggestions come to mind. One is I think as earlier discussed, zonal trading hub, a place where the prices clear essentially between those parties doing SE to SE trades, bilateral contracts at a zero price.

The other, another solution that we've vetted internally and I don't think has been brought up in any of the discussions and I've suggested it a little bit earlier, is currently the ISO with constrained resources basically identifies that resource in advance by a number of factors.

It identifies it by particular generator and the constraints that are associated with it and then there's a flag that's actually set in the template when you go to schedule it so the ISO operator or dispatcher knows that you have to operate it in this manner for some period of time.

What I'm suggesting is to the extent as a possibility is to the extent that there are long term contracts that not only the Department of Water Resources but folks like PG&E, probably the municipal utilities and maybe direct access customers have entered into in the zonal model, that those be identified in advance.

When the LMP bought market model is run for billing and salvage purposes, it does all of the things it's going to do but then it sums up the number of megawatts associated with the bilateral contracts and backs that out of the process and zeros out the price, again not making anybody any better or worse than they were when they started this process.

And do that over a period of time and the one thing I can tell everybody is DWR, at least CERS, is not going to enter into any additional long term contracts.

(Laughter.)

MR. GALLAGHER: I would like to follow up on that. I think there's a general agreement that, to the extent you can handle, this is really a transitional issue, the storage choice contracts are a transitional issue and they should be treated that way and to some extent they can be handled by negotiation depending on how the contracts are written. We got -- maybe CalPine is one of them. There's a relatively simple renegotiation that you can handle.

But to the extent that -- there are a billion or ten million dollars in additional costs that could accrue to the buyer side of these contracts, some of us are going to recognize that also and there are some contracts where the seller stands to really be a big winner as a result of the change in market design.

Those contracts are going to be hard to accommodate by a simple negotiation, at least everybody has no relative advantage or relative disadvantage. So we think that there is a role for the ISO to weigh in on this and we'd like to continue the discussion but we started in December with the ISO to try to think about some ways that would not make the market design seem optimal but that would recognize that there is a transition issue and that parties should be left off in relatively the same positions they started off in.

Somebody said these had been mentioned today and trading cap is one of them but it's not necessarily the end all and the be all but I think there's some more work that ought to be done along those lines.

CHAIRMAN WOOD: President Peevey's letter mentioned this particular issue and I just wondered, Sean, did you have some thoughts on what we could do in the coming months here as far as having guidance for us here to make those negotiations fruitful?

MR. GALLAGHER: I think it would send a strong signal to the industry if you encouraged the ISO to continue those negotiations with us and those discussions with us and with DWR and they should be opened up at some point to the supply side and if you made it clear to all involved that you expect to see some hard work and some hard thought put into this effort and want to see some progress.

CHAIRMAN WOOD: I mean, quite frankly, in the realm that we've seen in implementation of the New England market, which is maybe a little smaller than this market but still has complexities -- this was the only issue that was really an historic problem because it wasn't resolved. It wasn't kind of -- confronted.

So I would consider your invitation one that I would support in our -- part here today. That's -- handled before the market cuts in and before the market going much later.

COMMISSIONER LYNCH: And I would just note that it needs to be a little plain so that it gets everybody to the table rather than having one side or the other have to fight with one hand behind their back regardless of what one or the other did originally. You know you don't want have to fight a mistake.

CHAIRMAN WOOD: This is the whole setup from the entire MD 02 should not be an opportunity to refight an old battle but kind of treat people equitably as to where they are today on day one and it should be going forward in that you know efficiency the customers would gain.

So that's what we want to start here, not use this form. I think this came through the comments in terms of a little bit of what I heard that this has become an opportunity to kind of get a new leg up. I think that creates a bad environment for multilateral negotiation. That's what's going to go on in this building and others around the state for the next several months on these issues. Let's kind of leave the leg-up stuff outside the door if we can as much as possible. Because that's not going to result in free flow of commerce.

So thanks for flying that issue.

MR. PERLMAN: Can I ask a follow up question along those lines? When New England went to its locational pricing it had embedded its structure and trading hub in western Mass or central Mass.

Is there any time line issue with you being able to embed a trading hub into your process to meet this institutional LMP and you have to make a decision somewhere along the line or is that something that would not be problematic?

MR. THEAKER: I think that question is probably to me. I'll probably peek over my shoulder at Spence but I believe that the trading -- is one of the things we do constantly and is part of the implementation of this market and I believe I wouldn't have to answer and I would wait until somebody hits me on the head if I miss it. We plan for that functionality within existing software that would down -- if they implemented those without any substantial delays.

MR. PERLMAN: And if you had that, the lack of a delivery point that was the same as SB 15 or MG 15, would then exist and would be something the parties could utilize in substitution of the existing contract term if they so chose, I assume. Is that correct? Is that what you were talking about, Mr. Garris?

MR. GARRIS: Yes, along those lines. Something we improved to provide an equivalency at the, I think the exact details we could take the rest of the afternoon and just work on that aspect alone.

MR. METAGUE: Yes, the only thing I would add is of course we have a lot of DWR contracts and we're not looking for a windfall -- nor are we looking to end up on the northern side of the state -- to the extent that we develop trading patterns I think we would want to develop ones where there weren't additional congestion costs or costs allocated on either side that I would probably visit -- I think that what we should be going for here is that both parties are taking benefit. If the party has been breached and that this is a transitional issue, and if contracts go away they go away.

MS. SHIPLEY: I would just like to follow up on that tie-line proposal you were talking about earlier. As we move to, I guess the proposal would be to bring in things to T minus 20 where they get some contracts -- now I know for you that creates some problems -- but as we move into the LMP congestion management system, and you have a day ahead market and you have an hour ahead market, won't those problems in real time operations be eased by having those earlier markets for you? Would it be more possible at that point to have this T minus 20?

MR. THEAKER: I think that's a fair observation.

I would also add that I think part of this and I don't want to bleed too much from one panel to another but part of the ISO's reticence to let things wait until real time will go to a subsequent panel which is, you know, resource advocacy.

The ISO has some confidence that the resources are going to be there, you know, closer to real time. Then we will alleviate some of our concerns and maybe, almost certainly there's some timing with resource advocacy in them.

To the issue of, someone on this panel raised the issue of you know, load, as load continues to show up in real time without scheduling the forward markets, that's not my understanding -- but I believe the effectiveness right now of our real time markets are a dead market where we have a pretty full schedule in the forward markets and on balance the energy market tends to be looking for ties to go back on.

MS. SHIPLEY: Right, but once you influence the LMP pricing you don't have actually anchored back bids to deal with in real time.

MR. THEAKER: That's right. In fact, when we go to, when we go to --

MS. SHIPLEY: You won't be able to accept those into your schedules and so once you get it into real time you won't have this balancing gargantuan effort to deal with.

MR. THEAKER: Agreed. I agree. But again, as people have noted and as the Commission has noted, the problem of congestion stems from different time lines, ones that are beyond the contract versus ones that appeared in the market.

If we can align the contract time lines to the market time lines in a way that everybody is comfortable with and I'm sure that it's the ISO that's got some opportunity to deal with system problems for twenty minutes before the hour. That's the hopeful way. There is certainly hope that that could at get done.

MR. BANDERA: I would like to follow up on the whole considerable proposal that ISO has. From what I understood from the filing it seems that the ISO is going to redispatch in real time to accommodate the contracts basically and skip whether there are real time deviations that occur because of people's rights through an ETC. THe ISO is going to accommodate those items.

So then that brings me to Tony. If the ISO is able to accommodate the rights of the ETC holder through real time redispatch, why is there any need for the iSO to reserve any transmission capacity if, in effect, it is able to accommodate those transmission needs in real time?

MR. BRAUN: Let's break it into two parts, theoretical and practical. One, if you're a party to a contract, a customer in a contract, and you're paying a charge into the contract that allows you to forward schedule, and you find out that someone is actually now taking that capacity that you have reserved up until whatever you have reserved, that is, 20, 30, whatever that particular contract provides, but they're taking in the day ahead market. You can imagine that that doesn't elicit a positive reaction. So that's what I would call the theoretical.

To the practical, the ISO's proposal takes the congestion charge, it essentially treats the scheduler of that ETC as a price taker. It rolls the difference, it settles the load at a nodal basis, not an aggregated basis, as is the proposal for the rest of the load that I believe the exception is managed also -- and rolls up all of those charges, including the congestion charges, and it gives them to the scheduling coordinator for that transmission right.

Now Steve is concerned that he's the scheduling coordinator for that transmission right and sometimes he is.

But oftentimes the ETC customer is the scheduling coordinator for that transmission right so you've got a problem of past your argument where we're kind of battling as to who should bear the cost, but sometimes you just have a direct rate increase under the contract.

MR. BANDERA: So there are some instances where those congestion charges would be attributed to the ETC holder, is that correct, in your account?

MR. BRAUN: Absolutely.

MR. BANDERA: From your perspective, the problem is irrespective on the PTO side that they may get some charges, but for you, your concern is that there are some instances under an ETC that your following those contracts could result in the ISO billing you as the scheduling coordinator of that contract?

MR. BRAUN: That will happen.

MR. GALLAGHER: I guess I'll take the third side of this triangle. Tony's concerned about getting hit with some costs. PG&E's concerned about getting hit with some costs and not being able to collect them.

We're a little bit concerned that either IOUs will get hit with all the costs that come out of this proposal. They will collect them and they will see increased costs to IOU rate payers that are a result actually of improved efficiency across the whole system and if it's in fact a case that resolving end congestion is a benefit for all customers, I just assume it's a benefit for the entire system, it makes sense in our view to think about ways to allocate those costs across all user systems.

That is, it may not be appropriate for either Tony or Steve to get all these costs but to share them in a way that makes sense. That's the view that we've expressed in our part of the conference.

CHAIRMAN WOOD: What else have we got before lunch? Staff? Questions?

(No response.)

CHAIRMAN WOOD: Great.

PRESIDENT PEEVEY: Just like New York, right?

We're ahead of time.

CHAIRMAN PEEVEY: New York is always two hours behind.

(Laughter.)

PRESIDENT PEEVEY: All right, we'll break until 2:30 p.m.

(A luncheon recess was taken.)

A F T E R N O O N   S E S S I O N

2:30 p.m.

PRESIDENT PEEVEY: The record is on. We thank you all for actually coming back from lunch.

(Laughter.)

PRESIDENT PEEVEY: Shelton, take her away.

MR. CANNON: Thank you.

Good afternoon. We have had time to look at the agenda in somewhat broader perspective and we have with us Paul Clanon, who is going to give us an overview of the energy action plan and I think we're sort of, he's going to explain some of the issues that we're going to be talking about this afternoon. Paul?

MR. CLANON: Thank you Mr. Chairman, Mr. President, Mr. Chairman and Commissioners.

I'm Paul Clanon, I'm the staff director of the PUC's energy division. Thank you for scheduling me now. I think right after lunch is the perfect time to talk about resource adequacy.

(Laughter.)

MR. CLANON: I see that everybody has a full belly and you will agree with me that there is plenty of capacity at least until dinner time.

And between now and dinner time I hope to convince you that we're doing the things that we need to do in California to ensure resource adequacy both in the short term and long term with the 20 year long term planning horizon.

Shelton mentioned the energy action plan and that's one of the two key things that I want to focus in on in the brief 15 minutes I'm going to take up this afternoon trying to sort of set the stage for these panels this afternoon.

California has a reputation for squabbling not just with Washington, not just with the other western states but also within California. Significantly over the last year California led by some of the people up there on the dais have put its differences behind it among its agencies relating to energy, so the energy action plan is probably the most visible sign that the agencies are working together on questions where they weren't necessarily working together closely before.

And I know that was visible from the east.

With the energy action plan which dates back to May and which is a continuing series of meetings. There is in fact another energy action plan meeting tomorrow in Sacramento and I'm sure that some of the folks that are here today will be there tomorrow.

The energy action plan is an attempt by the energy related agencies in particular the PUC, the Energy

Commission and the Power Authority to work together on the stuff that we need that we know we need to do in California.

Energy Action Plan focuses in on six major areas and I'm going to tick them off quickly. I'm not going to spend a lot of time on each one. A couple I'm going to come back to and talk in some detail about what we here at the PUC working with the ISO and others are doing.

So six major things in the Energy Action Plan. Thing one is optimizing energy conservation, optimizing energy efficiency. California has historically been a leader in energy efficiency. That's a lead that California gave up in some significant measure during the '90s and we're struggling hard and aggressively to get back.

I see that Commissioner Kennedy has joined us. Commissioner Kennedy is the assigned Commissioner for Energy Efficiency here at the PUC.

(Laughter.)

MR. CLANON: And I'm glad her microphone wasn't on to comment.

(Laughter.)

MR. CLANON: We're aggressively moving to get back the lead in energy efficiency that we at least partly gave up.

To give you some scale of the decisions that the PUC is going to be making on energy efficiency, we are looking at proposals to spend on the order of half a billion dollars in energy efficiency investments over the next couple of years within California. Half a billion dollars in new investments looking for demand reductions, demand savings along the order of 500 megawatts.

So California's a big state. It has a big demand. But even with respect to the California scene those are fairly large numbers. And the California Commission is moving aggressively to implement those. I've got a good portion of my staff upstairs on the fourth floor of this building going over proposals today to get some of that investment out on the street in very early 2004.

So thing one in the Energy Action Plan, energy efficiency, energy conservation.

Thing two -- renewables. Now, there is again a longstanding history in California in support for renewable generation. There is statutory authority, statutory mandate in California now. We recently enacted the renewable portfolio standards which requires our investors in utilities to reach 20 percent of their procurement portfolio from renewables by year 2017.

So by statute, 20 percent of utility power is from renewable sources by 2017. The Energy Action Plan goes further. The Energy Action Plan calls for us to meet that 20 percent standard seven years earlier. That's in 2010.

2010 used to sound like a long time away. It doesn't any more. And California and in particular the PUC and particularly the Energy Commission are moving very rapidly to get the utilities up the renewables curve until we can meet that aggressive target by 2010.

Thing three -- ensure reliable and affordable electricity generation. This is the main topic of this afternoon and I'm just going to say a couple things about it now and then I'm going to come back in some detail.

Just to throw a couple of numbers at you, the Energy Commission has been very busy certificating new energy development in California since the electricity crisis -- over 8,000 megawatts have been installed and brought on line since year 2000 in a project certificated by the California Energy Commission. That continues today.

I know that you have read about sites whose developers have had to pull out and stop developing. That certainly has gone on in California during the downturn and since the end of the acute phase of the crisis but at the same time there is actual construction going on, new construction is slated to come on line in California in the next year or two and that's likely to accelerate as you will hear in some of the discussions and panels this afternoon.

The PUC is probably the point place for procurement among the state agencies and I'm going to spend the balance of my time talking about what the PUC is doing in procurement so I just want to lay the marker down now that California is building power and that the PUC is pointing toward certainly utility performance and I will come back to that.

Thing four -- transmission. Transmission policies and federal-state issues have been a focus here this morning and they are likely to be a focus again this afternoon. I just want to lay down a couple of things for you to keep in mind.

The first is that, despite what you may have heard, transmission has been building in California throughout the crisis, has in fact accelerated dramatically over the last several years. The PUC just working with the utilities that we regulate has completed 111, more than 100, transmission projects since the beginning of 2001.

And depending on how you total up the extra capacity brought in by those 111 projects, we get to some pretty big numbers. We're estimating 10 or 11 thousand megawatts of additional transmission capacity just since January 2001.

The PUC has certificated major transmission facilities in the past year. The PUC has also based on its judgment said "not yet" to a couple of facilities. It's the "not yet" that you tend to read about in the trade press but

I don't want you to come away today with the impression that the PUC is anti transmission or is a roadblock to transmission. Quite the opposite.

The utilities under PUC direction are the ones who are building the transmission.

Thing five in the energy action plan -- promote customer and utility on distributed generation. California again the leader of distribute generation early on, again some deceleration during the years of the crisis and the years leading up to the crisis, and a significant acceleration going on now. The PUC's role in that has been significantly to make decisions about things like stand by charges for developers of distributed generation and responsibility for stranded costs, particularly Department of Water Resources-related policies and some others that follow or don't follow distributor generation.

The PUC has been very active in making policy judgments in the area. This year we're looking to see a stronger acceleration of distributor generation. It's already out there, there's a 200 kilowatt distributor generation unit here in this building that's helping these lights on right now and the PUC is a strong supporter.

I said there were six things in the Energy Action Plan. That's five. That brings me to the last one and that is one that hasn't been talked about a lot today and I don't suppose it will be talked a lot about this afternoon, but whenever you talk about electricity in the United States and electricity in the west, you're also talking about natural gas.

Thing six in the Energy Action Plan is -- ensuring a reliable supply of reasonably priced natural gas.

I don't have to tell folks from the FERC or anybody here up on this dais today the concerns we've got about gas price spikes and the need for a resolution of the North American natural gas supply issues and certainly something that we're keenly interested in, you'll also find that the PUC is keenly interested in proposals for liquified natural gas terminals here in the west that will be an active area of policy making for California and for the PUC Commissioners in the next months and years.

So that's the Energy Action Plan. Those are six pretty heavy things. Those are six things that no one agency can do. Those are six things that not only a state can do and we recognize that very clearly here in California and that's one reason why we're very happy to see the folks here today who are here.

The Energy Action Plan was accused of being a feel-good document when it was adopted in May. I'd like to say that's a good thing, it is a feel-good document. But a lot more than that, it's also actually a thing that's being implemented in some pretty significant ways. I think that the folks who were involved in negotiating the Energy Action Plan and implementing it deserve a great deal of credit for that.

Let me get to procurement and let me just define what that means in the California context. It's a nice buzz word here in San Francisco and I want to make sure I define it.

When I say "procurement," what I'm going to be talking about is a proceeding and a process that's underway here at the PUC to implement the state statute 70 Bill 57 and also policy making at the state level and at the federal level around utility procurement, particularly electricity procurement.

We have underway a proceeding. We're going to see a proposed decision from the Administrative Law Judge here in a couple of weeks, in about two weeks, that's going to do some pretty significant things.

The first thing it's going to do is it's going to review and approve utility procurement plans. Now we're not just looking at 2004 although we are looking at interim procurement in the short term. We're also looking at five years. We're also looking at 20 years. So between now and the end of this year, between now and the first part of next year you'll see the PUC in California actually adopting procurement plans to go out as far as 20 years for these utilities.

We will be in this proceeding establishing policies for cost recovery mechanisms for energy procurement. That's a nice regulatory thing that just put at least one-third of the people behind me to sleep whenever you talk about rate making -- I'm going to wake them up now by saying this is how guarantee revenue stream. This is how you get utilities incentive to go out and sign long-term contracts. It's how you get utilities investors incentive to invest in utility construction and new generation.

So one of the key policy making areas of the PUC is keenly interested in is ensuring the rate making for utility procurement is set up to encourage resource adequacy. This may be the most important thing the PUC does in procurement.

Several others just to hit on -- you'll see the PUC adopting a target capacity reserve factor, an adequate reserve margin. The utilities have proposed jointly a 15 percent reserve margin in that proceeding and you're likely to see the Commission coming up somewhere around there potentially phased in over a several year period.

We will be implementing a long-term procedure for ensuring resource adequacy. I don't have to tell anybody here today, you don't just do this once and then forget it.

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It has to be a process. It also has to build in the possibility of uncertainties and crises. We have to make sure that you don't cut down on your potential options and the PUC is keenly aware of that.

Finally in those proceedings the Commission will be ensuring that the renewable portfolio standard is met. As I said earlier, that's looking very good and the utilities are making good progress and the Energy Action Plan calls for moving to 20 percent of utility procurement from renewables as early as 2010.

So that's what we're going to be doing between now and the end of the year and during the first part of next year. To put you on the page I'll give you just a very brief introduction to what we've done to date to try to give the folks on the next couple of panels some specifics perhaps to build on.

Starting January 1, 2003 -- actually let me take it back -- shortly before that. Before January 1, 2003, we had the utilities, one which is bankrupt, another was then and continues to be below investment grade credit rating. We had the utilities essentially out of day to day procurement. The Department of Water Resources was active in the spot markets to cover the residual left short -- that was left over after the Department of Water Resources long-term contracts were called on and basically dispatch was being done by our friend, Pete Garris, and the folks at CERS in the Department of Water Resources.

Starting January 1, 2003, despite the folks who said that it wouldn't work, despite the folks who said that the PUC wouldn't have the guts to do it, the utilities took over procurement and, since January 1 of '03, the utilities very successfully have been dispatching the Department of Water Resources' long-term contracts that were allocated to them -- that is, they were doing the day to day operational dispatch of those contracts. Utilities are also doing the hour by hour and 15 by 15 minute spot purchasing to cover the mass load.

So despite people's concerns that the utilities would be unable to cover procurement again after the crisis, not only are they but they are doing a very successful job of it under the rate making that I talked about just a minute ago.

During 2003 we've had the utilities doing some interim procurement. It's been a very difficult cart before the horse sort of issue in California because, in order to be a rational public policy makers the PUC Commissioners working within the state structure had felt the need to have long-term procurement data, forecasts, proposals, before they could start making day to day decisions about where the utilities should be building power plants, signing long-term contracts for power or doing some combination of both.

At the same time, there are targets of opportunity. There are sometimes fleeting targets of opportunity that come and go that have made sense for rate payers for the utilities to jump on early even before the Commission adopted long-term procurement plans.

Also at the same time there were technologies in particular renewable technologies that were attractive and that the PUC working within the state policy structure wanted to encourage.

So you saw the PUC adopting in 2003 some significant amount of contracting, some fairly long-term contracting between utilities in both renewable and non renewable providers outside the regime of an adopted long-term procurement plan and competitive solicitations across the board -- very difficult decisions for the PUC to make.

Nobody likes to have to have to make those sorts of decisions but the PUC Commissioners but the bullet and wound up approving something like 1,600 megawatts of long-term contracts between utilities and third party power providers both renewable and non renewable.

Finally in 2003 we got the ball rolling for the future. Utilities have not been doing long-term procurement plans. Really no one has. The last time anyone in California has done a 20 year procurement plan, even

President Peevey was in short pants.

(Laughter.)

MR. CLANON: So we had the famous culture shift to enacting California -- not only were we going to be doing something no one had done for a long time, we were going to be asking the utilities to do it given that the utilities were in a situation of not being credit worthy or even actually being bankrupt.

I am proud to say that the utilities were able to do that, not only to take over procurement but they produced the sorts of long term plans that the PUC is reviewing now and is going to be approving some -- up here between now and the first part of next year.

I am conscious that I do not want to be sucking up time from these panels. Let me just make a couple of more points about these long-term procurement plans and then I will turn the mike over.

What you have to look at in these long-term procurement plans? Well, we just went through the energy crisis of 2000 up to today. California knows a hell of a lot about what can go wrong. I think that's been one of those wonderful learning processes that we could definitely take advantage of now to look at questions like what is the proper mix between utility ownership of power plants versus long-term contracting versus operations in the stock market.

If you decide that it is a mix that you're looking for, how do you ensure that there is enough certainty in the market of payment for third party investors to invest in new power plants? Under what circumstances does it make public policy sense to find rate payers for long-term contracting in order to ensure the existence of merchant power?

So you're going to see the PUC biting off that very difficult question here in the next several months.

Energy efficiency -- I said that the -- a peak feature of the Energy Action Plan is to ensure that every bit of cost effective energy efficiency is taken advantage of in California. And we need to do that for all sorts of reasons I don't need to elaborate on.

But I also don't need to elaborate on the difficulty of comparing energy efficiency to a new power plant. You can't just walk away from that issue and say, "oh, they're not comparable." You have to figure out a way to compare them.

And we'll be doing that here at the PUC in the next several months.

What is the proper reserve market? There are going to be people behind me who are going to argue it all the way from they want really well-reserved margins and to lower rate payer costs, to in order to make sure that competition happens among the merchants, you need higher reserve margins. The utilities have come to the PUC and recommended jointly a 15 percent reserve margin. PUC is going to have to make that potentially very difficult. A one percent change in that reserve margin is big dollars to rate payers and a one percent change in that reserve margin has potentially big impacts on the way this market functions.

Finally just the last two markers. Let me lay them down -- what is the right role for utilities in this market? Should utilities be owning and building power plants? Should utilities be agents for rate payers in signing long-term contracts? Should utilities be out of this business entirely? Should we go to a more core-non core sort of function where some customers decide not to rely on utilities for purchase of electrons altogether?

The PUC can make that decision alone. It's an active area of legislative interest here in California and the structure of the industry in California will ultimately be decided likely through legislation. But we're certainly a key player and the PUC Commissioners are likely to be making some pronouncement in their public policy around procurement that will help Sacramento make that decision.

Finally I started out by saying the rate making is one of those things that puts you to sleep but it may be the most important thing. It's the rate making that's set here by the PUC under 70 Bill 57, under the procurement statute that's going to decide, it's going to implement how this market gets structured. The rate making can get it right and we can have financially stable utilities that are able to procure power at reasonable terms for the rate payers or we can get it wrong and the utilities can remain sub-investment grade quality and unable to engage in long-term contracting except at very high prices and unable to do building.

We can get it right or we can get it wrong. We're going to do one or the other here in the next several months.

(Laughter.)

MR. CLANON: And that's generally a good way to start off. Thank you.

CHAIRMAN WOOD: Thank you, Paul.

The next panel here is going to be looking at what may be one of the most urgent issues, one we are certain will be -- on the conceptual -- what's the appropriate balance that can be calibrated, meaning, you know, resource adequacy requirements in the market pool which maintain mitigation, how do those two things sort of fit together in a way that makes sense and in a way that they all support in a new market design.

There's a very hard question in vetting in all this that's sort of trying to look at customers in the short term versus looking at investment decisions and how you protect customers and how you insure the financial health of the marketplace in the longer term.

So I am looking forward to hearing what the five panelists here have to say about these issues.

With us today we have Keith Casey. He's the Manager of Market Design with the Cal ISO. We have Jan Smutney-Jones, Executive Director with IP. Jim Hendry, Planner with CBUC. James Bushnell, Research Director, University of California Energy Institute, and Ernest D. Blick, Director of Asset Commercialization-West and Reliant Resources, Inc.

With that, Keith, if you can kick it off fur us, that would be great.

MR. CASEY: Good afternoon. Thank you, Shelton.

Good afternoon, Chairman Wood, Chairman Kissinger and fellow Commissioners. It's a pleasure to be here. I think this panel is addressing a very critical issue which is whether the new California market structure, which is really defined by the ISO in the '02 design, and the procurement rules and resource planning rules that come out of the CPUC procurement proceeding -- at the risk of stating the obvious

I think it's critical that those two pieces fit together to provide a viable structure. And really what this panel is addressing is -- does it?

Does it provide a viable, sustainable, stable market structure?

I'd like to offer some initial comments and what the ISO sees as the critical elements of a resource adequacy plan, and how those elements fit into or relate to the ISO MD 02 design, particularly the market power mitigation measures.

The ISO believes that a research adequacy requirement promotes serving entities as a critical component of the overall wholesale market design. A resource requirement is needed primarily for three reasons.

One, to provide a long-term platform for future investment in California's electric infrastructure and maintaining adequate revenues for existing generation needed to serve load. The second, to support in the shorter term, reliable system operations. And third, to mitigate the amounts and effect of market power by encouraging utilities to enter into long-term contracts.

The ISO has been very active in the PUC procurement proceeding and in testimony and during the hearings we've laid out features that we think an effective resource adequacy requirement ought to include -- the first being a well-defined requirement that the utility procure on an forward basis sufficient resources to meet their projected peak load plus adequate planning reserves and with reasonable limitations on reliance on shorter term and spot market purchases coupled with fair and ex ante cost recovery rules.

Secondly, consistent definitions in accounting conventions of what constitutes eligible capacity.

Third, a process to review the procurement plans with particular emphasis on deliverability. And transmission planning is key here. We want to make sure that, if utilities are entering into long-term commitments they factored in what transmission is needed to get additional supply to load.

Fourth, in explicit -- and this is a very critical issue for the ISO -- an explicit obligation to procure at least one month ahead of time 100 percent of the utilities' peak load and planning reserve requirements and to make those resources, or make a demonstration to the ISO that those resources are available.

The fifth is really the critical coordination with the ISO so that, on a day to day, hour to hour real-time basis we know precisely what resources have been identified as being critical for serving the utilities' load and those are available on the ISO's markets for dispatch.

And then, finally sixth, well defined

consequences for utilities that fail to meet their resource adequacy obligations.

So I'd like to underscore a couple of issues that are of critical importance to the ISO, the first is the necessity that the resources identified under the procurement plans are coordinated and hand off to the ISO so that they can be fully utilized in the ISO's markets.

The bottom line is, unless these resources are efficiently made available for dispatch in the ISO's markets, one has to question the value of the resource planning because ultimately the buck stops in real time. We need to know which resources are available and make sure we fully utilize them in the real time market.

Secondly, as you heard earlier, there is a joint recommendation for a phased in approach to resource adequacy that has the support of the utilities and a number of state entities.

The ISO is on the record of expressing significant concerns about that proposal. We feel it is placing too much reliance on the spot market. It lacks a, what I spoke to earlier, of a month ahead verification to make sure that the resources under the procurement plan are actually available to the ISO and the reserves that were offered under that proposal in the phased-in approach in our view are too low and a four-year phase-in is too long.

The critical thing from our perspective is, this is prime window for actually stepping up and getting the resources needed to serve load.  We have depending on whom you talk to, a surplus of generation throughout the west right now.  This is a prime opportunity, while market conditions are moderate, to capitalize on it.

So in summary we believe that a resource adequacy program, if adopted along the lines defined above, will address several of the questions posed to this panel.  It will create a structure that supports long-term infrastructure investment.  It will result in appropriate signals for load and generation to forward contract and finally it will provide an appropriate mechanism for financing new power plants and ensuring that existing generation, to the extent it is needed to serve load, has an opportunity recovery that's going forward fixed costs.

I know I'm running long.  I'd just like to quickly touch on the relationship of resource adequacy to the ISO market design elements.  Fundamentally the ISO's MD 02 proposal provides for operational cost recovery in its markets, meaning that resources committed and dispatched in those markets are guaranteed recovery of their start-up minimum load and operating cost and, moreover, to the extent they are infra-marginal in the sense their variable cost is below the market clearing prices, there's opportunities for revenues to contribute towards fixed cost recovery.

We do not view the ISO's design as being the primary vehicle for a recovery of going forward of annual fixed cost, nor do we think the design should be altered in ways to try to provide a mechanism for recovery going forward to annual fixed costs.

The FERC Commission has itself has acknowledged that the primary vehicle for fixed cost recovery is long-term contracts and we think the resource adequacy rules from the PUC will be the vehicle for facilitating the long-term contracts.

With respect to the market power mitigation measures, we strongly view the market power mitigation measures that were proposed in our filing as striking the appropriate balance between providing cost recovery and opportunities to earn additional revenues, to contribute towards fixed cost recovery.

So again, the resource adequacy program is where we really look to for the vehicle for ensuring new investment and ensuring that the annual fixed cost generation is recovered.

Now, the ISO understands that some suppliers unfortunately have not, were not able to successfully negotiate long-term contracts during the energy crisis and, as a result, some of the facilities in California are being mothballed -- temporarily retired. That's clearly an unfortunate situation but we strongly believe it's a situation that has to be addressed through the procurement proceeding, not through trying to alter the MD 02 design to remedy that situation because fundamentally it's a delicate balance we struck in the design and the mitigation elements and to the extent you start modifying those you create unintended consequences.

And we are concerned particularly with some of the decisions in the recent FERC order on MD 02 relating to the RIC process as well as the must offer obligation and we welcome an opportunity to discuss those with FERC staff and Commission at a later date.

So with that, I will conclude.

MR. SMUTNEY-JONES: Thank you very much. I'm Jan Smutney-Jones. I represent the Independent Energy Producers Association and I felt a little like Bill Murray in Groundhog Day earlier today of sitting through the discussions that we seem have had for the last five years and let me see if I can add to that.

(Laughter.)

MR. SMUTNEY-JONES: We've been talking about planning and procurement in this state since I began in my current job about 15 years ago. So I'm not sure I can add anything new but maybe I can characterize it a little differently. We represent about 20,000 megawatts of generation that includes about 90 percent of the renewables in this state, large percentage of Co-Gen, some of the other resources, divested resources, and a lions share of the 8,000 megawatts that have come on line over the last few years and that's all very good.

The FERC order request asked the question, 'what do we need to do to encourage future investment and make sure that that base there remains available to the people of California.

Let me say that I thought that the opening sort of discussion between the two Commissions was very helpful.

This is obviously a nexus between what are the real issues that the PUC faces with respect to what are the appropriate reserve requirements of people of California, but more importantly, how much are you willing to pay for it? And the issues that FERC is concerned with, with respect to how do those decisions affect the wholesale market.

So I think this is a very, very crisp issue that hopefully you will continue to engage on.

Our opinion is an enforceable resource adequacy requirement which requires low serving entities to meet their capacity needs will help drive investments. And something along the lines of understanding exactly how much power needs to be added over a period of time and providing a revenue stream will obviously attract capital to build power plants.

I think it also provides significant protections about localized market power because obviously if you've got resources under contract, you can basically take care of your own risk profile.

It is our hope that the procurement proceeding may provide a basis for creating some contractual opportunities. Obviously the order is not out so we don't know. But this in turn we hope will drive the necessary revenue stream which will allow us to both construct new facilities and modernize existing facilities.

It will also provide an opportunity for QFs who are currently under contract and many of those are falling off of contracts, both co-gen and renewables, a place to go with their plight.

However, it is of critical import and this is going to be our mantra for a long time now, that these processes happen in an open, transparent and competitive manner and it's extremely important that we recognize the fact that, in the generation sector, there has been a lot of competition for a long time to build power plants and the rate payers have benefitted from cost of those technologies being driven downward and that's because it's largely been competitive.

We believe that this process needs to move forward and quickly. I will note, perhaps if Commissioner Loretta Lynch share a similar concern about market power, although from radically different perspectives, currently we have had some of these procurement that Mr. Clanon talked about, but they're being driven largely by the buyers.

Now that wouldn't be a problem if the buyers also didn't want to get into the business of being suppliers and there is a real tension here that's occurring because we've got these sort of processes that are happening outside of organized procurement process and it's causing a great deal of concern with respect to the lack of transparency and where we're going to go.

Hopefully I am wrong and in two weeks I can sit down and shut up because everything I'm worried about will go away. We'll see. I'm sure you hope that, too.

(Laughter.)

PRESIDENT PEEVEY: Go away, yes. But shut up? Never.

(Laugher.)

MR. SMUTLEY-JONES: Yes, yes. I'm just going to jump over this real quick. There's obviously a need for a robust day ahead market that everybody understands how it works and that's obviously critical.

Now, sort of concluding here -- our industry obviously recognizes the need for rules addressing local markets addressing local market power. And this is not a debate on that. Those rules must be clear. They must be monitored and properly enforced.

However a big issue has been the use of the must offer provision as a surrogate for a resource adequacy requirement. And that we believe would be inappropriate use of a necessary market power tool.

And while we think the FERC order strikes that balance, it's obviously the PUC shares some concerns there or has some concerns there and I would certainly encourage you to keep this discussion point open because what gets lost some times in the litigation is people believing that, well, gee, people don't want any market rules, which is not the case. The real issue that's really driving this is that the rules that were put in for very explicit purposes are being used for something that they were never intended to.

Ultimately we're going to end up with the question of accountability and I think this is the one area that no one is talking about. Last year the power agency on behalf of the joint commissions came to the ISO and requested from Chairman Kahn and his colleagues a year to sort of get the program together in RAR and I think he quite wisely and appropriately said, "Please bring us your best work" and hopefully that is what the product, at least of the procurement proceeding, will be.

But it's essential that the state follow through on that. I don't think anyone is debating the proper role of the state in this but it's very important that that's followed through on.

Moreover on accountability on a larger basis, the question is, who and how will the RAR be enforced in the future? What happens if it is inadequate? And this is particularly important because if everybody was just under the jurisdiction of either one of your agencies, that's an easy problem to solve, but as someone pointed out earlier, there are 25 percent of the customers in this state are municipal utilities which are not regulated by either one of your agencies and I'm not here to advocate that they are -- I don't want to be stabbed in the back by Mr. Braun.

But you also have other load serving entities and this is a legitimate question -- what do you do? And this is not a hypothetical. In the middle of the crisis, we in Northern California, some munies who were resource adequate had rolling blackouts. I know because I live in one of them. And this is sort of an open question in a very, very real problem, and has driven actually the municipals to respond in ways that perhaps most of us or a number of us, would not like to see them go.

And the bottom line is, what happens if we fall short? So in closing here, we would strongly encourage these Commissions to stay focused on this issue because this is really where the rubber meets the road for both of you in some very, very, real meaningful ways.

The RAR must be grounded in open transparent and competitive process. Utilities, I believe are perfectly capable of competing in those bids as long as they're held accountable to it. Just so we're clear on that.

And that we can keep very, very focused on this.

We don't have a lot of time on this. If I'm reading the ISO's five year forecast correctly, and that's always dangerous when you put numbers in front of me, but it looks to me like we don't hit with the resource or reserve requirements in any summer over the next five years and we're dangerously close in high years with respect to falling below our operational.

This chart was done before 2,000 megawatts of old stuff just announced over the last month, that they're shutting down over various times over the next several months.

So we do have an existing fleet of resources out there that are getting their out cards right now, they're very old power plants, and they're going away. And we have a very narrow window that we can address some of these issues and they're big issues. And I do appreciate your time. Thank you.

MR. CANNON: Thank you.

Jim?

MR. HENDRY: Thank you, Commissioners, for the opportunity to address you today. My name is James Hendry.

I am with Strategic Planning Division of the Commission.

To begin with, the CPC would like to thank FERC for recognizing the strong state role in resource adequacy in its recent order. Although the draft decision has yet to be released, as President Peevey stated this morning, California is seeking to ensure that there is reliable service, sufficient reserves and incentives for promoting new investment.

Because there is no draft decision out yet I would instead like to talk about three broad observations. First, the paradigm about how the eastern ISOs have chosen to address capacity issues may not be fully appropriate for the California market -- one size does not fit all and differing approaches for different regions may be appropriate.

California is not developing its resource adequacy to primarily work as a blank slate. First, California has a legacy of the DWR contracts which were entered into in part by the strong urging of FERC and have provided reliable service.

However, the majority of these contracts, about 6,000 megawatts, are not tied to specific generating sources. Just this President Peevey noted the CPUC's concerns about how these contracts would fit into the LMP CRR paradigm, it is equally unclear how these contracts might fit into various resource adequacy proposals that have been broached.

The second perhaps most important is state control over addressing resource adequacy and this allows California to address its energy future. As Paul Clanon just noted, CPUC has set an ambitious goal to meet most of its new energy needs through energy efficiency, renewable energy and dynamic pricing demand response programs.

It has proven exceedingly difficult to include these types of soft resources into the resource adequacy programs of the eastern ISOs because these programs are strongly biased toward, to use the industry phrase -- iron in the ground.

A perfect sale pursuant to the October 28th order appears to show some of these concerns when it is stated that "rushing to relieve inadequate regional supply is to reduce high regional spot prices may bias construction towards choices -- towards supply resources that can be constructed quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals.

It is our hope that FERC will work cooperatively with the PUC to give California the time and flexibility that best meet its energy needs.

A second observation is that there needs to be more empirical analysis of the incentives in the ISO's market design that they should design, retain and attract new, investments.

For example, this -- concern that low spot prices encourage load to over rely on spot markets, actual spot market purchases over the last few years have remained at about three percent lower in a rounding error.

Notice the ISO's market mitigation is toward new construction with about 8,000 megawatts of new power plants coming on line over the past year. In its filing the ISO strongly addressed the issue of revenue adequacy in the various revenue streams available to generators to recover their costs. Although the ISO did not have the capacity market it does have about 9,000 megawatt reliability and must run contracts, 10,000 megawatts of DWR long-term contracts and -- service payments that are generally higher than eastern ISOs.

And it should be noted that the CPUC also supported, although at slightly less general levels than FERC adopted, the ISO residual unit commitment payment process.

Overall the ISO and CPUC have advocated the combination of the ISO's market design plus the ongoing efforts of the CPUC in the procurement proceeding should provide reasonable opportunities for investors to recover their costs in making these investments.

The final observation, continued linkage of resource adequacy to market mitigation. The CPUC has used resource adequacy as complimenting, not substituting, for market mitigation.

For example, the CPUC strongly believes that the must offer requirement is a valid condition of market based rate authority needed to prevent the physical withholding of capacity. Such requirements particularly are appropriate in the electric market where electricity, unlike other commodities, cannot be stored.

This October 20th FERC order, FERC appeared in its discussion of day ahead versus real time must offer for the must offer requirement is a valid market mitigation tool. In the FERC order in its discussion of resource adequacy the order once again appears to incur must offer requirements for resource adequacy requirements.

We hope that in its final order FERC will reaffirm that this is a valid market mitigation tool.

Finally I think we want to state that we agree with the ISO that the way that power plants get built is through long-term contracts, not reliance on spot prices. And we therefore agree market mitigation is trying to strike an appropriate balance that the ISO knows between trying to deter a load from over relying on the spot market, which is a concern of the FERC, but also I think there is a mirror image of that that you do not want to make the spot market so generous that generators have then an incentive to essentially try to play the lottery and withhold capacity hoping to make a big score in the real time in their end markets.

And we think the ISO should start to try to achieve that balance and we think they did a very good job in that.

Finally it is noted that the PUC is addressing the resources under its control. I would like to address Jan Smutley-Jones' comments about the municipal utilities.

The Commission does not regulate the municipal utilities although both the ISO, the Commission and the CPUC in their review of them, have found that even during the energy crisis they remained resource adequate.

In Amendment 46 which FERC approved it allowed many municipal utilities to choose the option of becoming needed subsystems which essentially allows them to island themselves and therefore barring any sort of outages that may be imposed by the inability of others to procure or acquire sufficient load, this in addition to many municipal utilities being resource adequate in and of themselves.

So I think this is one way in which municipal utilities have sort of sought to be addressed by the ISO and FERC so that they can be covered under resource adequacy and not be affected by imperfections of the marketplace. Thank you.

MR. CANNON: Thank you.

MR. Bushnell?

MR. BUSHNELL: Thanks for the invitation.

Just about everybody I know has asked me to make clear that I'm going to be giving my opinions alone and not those of any institutions I am affiliated with, particularly when I'm not going to be representing the markets available to the ISO of which I am a member. I am just giving my opinion.

I was just going to talk a little bit about the PUC procurement procedure and just give my take on where I see it going and how those things could play out and maybe offer an alternative -- and secondly talk a little bit about this link between resource adequacy and what I would call market power mitigation. I'm not sure we want to be mitigating markets although we do do some of that, too.

(Laughter.)

First I want to take a step back, though, and make the observation that it appears that we're making policy as if the California crisis was caused primarily by the fact that the market couldn't be generation built and that we didn't have enough generation capacity. And I at least do not view that as the primary cause of the crisis.

Certainly we had lots of generation built in the last two years and if you look at California in comparison to other markets around the world and in this country, the thing that really stands out that differentiates the California market from the others is the lack of long-term forward commitments, the lack of contracts, convertible or negotiable or whatever you want to call it.

And I think almost everybody now agrees that this was a problem to varying degree and they want to fix it. And the real question is how we go about doing that. There's really two views to this. There's providing better incentives for the load serving entities to sign contracts or eliminating incentives for not doing so.

And the alternative position is to essentially establish mandates for requirements for a certain level of contracting, forward arrangements or other kinds of things.

And we have to make some decisions about that. You're sort of hearing I think different articulations of different points of view on that. And I'll probably be articulating mine.

So first turning to the procurement proceeding which is really about this question about signing contracts or making some kind of long-term commitments, underlying this is the question of who's making commitments for whom?

It appears the state is leaning towards, and it's really now the fact that that the state has a core-non core separation of customers. You have some customers who have retail choice and some others who don't. And probably we will be moving along in some kind of framework like that although this is not completely decided -- so really these questions are divided into two sets.

We have these core customers. We have to figure out how to procure or sign contracts to serve them. And it looks like we'll be moving towards some kind of integrated resource plan approach for that set of customers. There are alternative ways to doing that sort of thing, instead of focusing on what generation or energy efficiency or other forms of resources we should acquire for those customers, what we could instead focus on is allocating the financial responsibilities for serving those customers.

This is the approach taken in many of the eastern states where you have certain chunks of the retail service auctioned off or transferred to other firms. Basically you have a firm take on a non ambiguous financial obligation to serve customers that some break -- some sense -- of the rate.

Once you have that obligation and once it's unambiguous they have a pretty strong incentive to hedge that risk.

Of course, I think there needs to be some kinds of standards overseeing the financial viability of the firms that would be providing these kinds of services to avoid the situation like the NRG situation in Connecticut.

But that is a slightly different focus which is on the financial aspect, the financial risks of serving customers rather than on the physical resources and I believe that if you provide the strong incentive to provide this financial risk, to sign contracts, the resources following, you got to sign contracts with somebody. And the firm that's signing the contract with the counter parties probably is going to be in a better position to verify whether these resources are real, whether they have enough gas, whether they haven't sold power to somebody else, and all these other sort of accounting problems that goes with trying to verify a resource requirement.

Again, this is just my view. An alternative to acquired resources would be allocating the financial responsibility unambiguously.

For the non core customers we have this

interesting situation where who's going to buy their resources? Or who's going to insure their resource adequacy? One idea would be well, we have the utilities sort of cover them, too, because we're worried about them just free riding. If the utilities acquire a big reserve margin, and they find a reserve access customer, maybe I'd feel pretty good that there's extra generation around I don't need to acquire.

So that's been a concern. To get around that one idea would be to have utilities explicitly plan for reserve for those customers and send the bill. I believe those customers are not enthusiastic about that process.

The other alternative would be to make them explicitly responsible for the consequences of a potential lack of resources that they have. I think everybody who has direct access in this state should have a real time meter, should have an interval meter, should know how much power they're actually consuming and should have some -- ISO should have the physical ability to cut them off if their retailer had not acquired enough resources.

And if that happens then we'll see. I think firms go to retailers who have enough resources and they will be taking care of that, but the planning process will not be directly overseen by those overseeing it for core customers and maybe we could do different outcomes.

Certainly there are some people who think that retail choice gives us completely different outcomes.

So just briefly on this notion of resource adequacy and how it relates to market power mitigation, it's been offered that there is a link between some kind of capacity payment or capacity obligation and these forms and the market power mitigation that was in MD 02 or other forms of mitigation.

It's my opinion sort of looking at this, that many elements of this mitigation, if the cost of having it is a capacity market, particularly one like PJM's, it's not worth the cost. I think that we should think more about mitigating true market power but not mitigating markets in the sense of allowing prices to go higher when we have true periods of shorter resources and not requiring firms to have a specific mandated target of acquiring resources as the alternative to that.

I think that this is the better choice that leads to a more efficient outcome and it's better for buyers because they always have the option of signing a contract and avoiding a higher stock price as opposed to essentially mandating that they do it and enclosing a lower more mitigated price in exchange.

But I think it is important to distinguish between bid mitigation and those sorts of things that are intended to just prevent firms, particularly those in local -- with local market power, from exercising their market power, and other forms of mitigation like the wholesale price cap. I don't think there's anything in a properly assigned bid mitigation that necessarily has to conflict with the recovery of fixed costs.

So it does boil down to this price cap question and I think if it comes to a trade off between having to have some fixed payment thorough a capacity obligation and a higher price cap, I think customers are better served by not being forced into a capacity obligation.

Thank you.

MR. CANNON: Thank you. Mr. Kebler?

MR. KEBLER: Good afternoon. My name is Curtis Kebler on behalf of Reliant Power and I am pleased to provide these comments to the FERC, the CPUC and EOV on the issue of resource adequacy and local market power mitigation.

I hope our comments will be received in the spirit which they are offered, which is to provide constructive and helpful suggestions on how we can move toward the shared goal of creating a robust wholesale electricity market that benefits consumers in California and throughout Western America.

In general we agree with the Cal ISO's assessment that the Commission's recent order on MD 02 was a step in the right direction. While the order is advisory in nature, because it addresses the conceptual market design elements submitted by the ISO in July of this year, it appears to provide the necessary guidance to allow the ISO to proceed with the development of software and tariff modifications.

The order also provides the constructive framework for addressing issues that are not yet fully developed. Overall, we believe the order recognizes the critical relationship between resource adequacy and market mitigation measures and the importance of achieving an appropriate balance between the obligations and responsibilities of buyers and sellers in these two areas.

In particular the order notes that, while resource adequacy issues are being addressed by the CUPC in procurement proceeding the ISO market design proposal must also include a resource adequacy element. The order notes that the lack of the resource adequacy proposal in the ISO market design leaves a critical balancing element of the overall market design subject to the outcome of the CPUC's proceeding and believe with such issues such as resource adequacy, that mitigation should not be dealt with in isolation. The order directs the ISO to submit a filing outlining changes to the proposed market design within 60 days of initial decision by the CPUC in its procurement proceeding. Such a decision is expected by the CPUC in December of this year, as we heard earlier.

Given the mitigation measures in place today, Reliant believes that a well-designed resource adequacy mechanism is of fundamental and foundational element of an overall market design. We believe a well-designed resource adequacy mechanism should be forward looking, ideally three to four years forward, to reflect the time it takes to develop and construct new resources. It should require a demonstration of physical infrastructure, not financial contracts, and it should include a delivery requirement to ensure that resources being counted on can actually be delivered to the load where it exists on the ISO grid.

To date, the procurement proceeding has focused primarily on minimum reserve margin requirements for load serving entities. We believe however that resource adequacy is a broader concept and must include a standardized procedure for accounting capacity and ensuring that there is now double-counting of megawatts or relying on virtual megawatts that cannot be delivered to load within the grid.

These resource adequacy procedures should be transparent and roles and responsibilities of the various entities should be clearly defined and these entities include the ISO, the utilities, regulators and suppliers.

Paul Clanon in his remarks mentioned the idea of a phase-in of a resource adequacy requirement. In the procurement proceeding, the joint recommendation submitted by the utilities and the CBC recommends a seven percent reserve margin requirement in 2004 and an ability to rely on spot capacity purchases to meet this requirement.

The ISO on the other hand as we heard from Keith proposes 17 percent reserve margin requirement that applies on a month-ahead basis as straight deliverability requirements and requires 100 percent firm capacity resources on a month ahead basis.

We believe that the choice the Commission makes concerning these issues in effect defines the roles and responsibilities of the various entities.

These issues, in effect, define the roles and responsibilities of the various entities. To the extent the ISO has responsibility for ensuring reliability of the grid, it must have the tools to accomplish that goal. And that means it must have resources known to it in advance, so it can commit and dispatch them in ways to meet the reliability needs of the system.

If, on the other hand, the utilities and the CPUC are responsible for reliability, then that should be clearly stated, and the reliance on the seven-percent reserve margin requirement should be clearly stated as such, and the ISO's responsibility then is to work within the confines of that resource base.

I'd like to offer an example on the issue of the relationship between resource adequacy and market power mitigation, an example in which, if we had a resource adequacy mechanism along the lines of what the ISO has proposed in the procurement proceeding where we have a 17-percent reserve margin requirement applied on a month-forward basis, it's applies to firm resources only, and it has a deliverability requirement.

In that kind of a construct for resource adequacy, the local power measures take on a very different structure, because, in large part, the load-serving entities would have control over the resources. They could make them available to the ISO for commitment and dispatch, as needed by the ISO to meet local reliability needs.

If, on the other hand, we had a resource adequacy requirement that is limited or applies to only a seven-percent reserve requirement, then that applies a very different type of local market power mitigation measure because in that construct, we will have a large quantity of uncommitted resources which must be dispatched for reliability reasons, but which have no other means of fixed-cost recovery.

President Peevey, in regards to the letter you mentioned this morning, you indicated some dissatisfaction with the Commission's decision not to adopt the ISO's proposal on local market power mitigation.  The way I read the decision, was that the Commission was recognizing the relationship between resource adequacy that is being addressed by your Commission, and the issue of local market power mitigation.

And because the issue of resource adequacy has not been yet addressed by the Commission, it is, as a practical matter, difficult for the FERC to adopt the decision on local market power mitigation in the absence of knowledge about what the Commission's program is going to look like.

So, ultimately, when we see the Commission's program in December of this year and the parties have a chance to review that and collaborate in the manner that the FERC has proposed through this process of technical conferences, we can evaluate both the provisions of the CPUC's resource adequacy mechanism, evaluate those in the context of the various local market power mitigation measures, and create an integrated market design that accomplishes the balance that the Commission and all the parties are seeking to achieve.

Let me now turn to an issue involving the ISO's proposal for residual unit commitment proposals. We believe the RUC mechanism is an essential feature that an ISO must have available to it to ensure that it can commit adequate resources to ensure reliability.

We believe, however, that the RUC mechanism proposed by the ISO did not provide an adequate opportunity for fixed-cost recovery by generators, particularly those that operated over-capacity factors and are used primarily to provide reserves. So were encouraged by the FERC's decision to modify the ISO's proposal to create a better balance between the obligations of sellers and buyers.

Let me now turn to a few comments about the path forward over the next couple of years: As we heard this morning, MD02, Phases II and III, have now been consolidated and are scheduled for implementation in late 2005, about two years from now.

Reliant is concerned that there are structural imbalances in the market today that need to be addressed immediately to ensure that resource adequacy can be assured over this two-year transition period until MD02 is implemented.

The issues involved require the operating reserves required by the ISO to reliably operate the grid and the procedures used by the ISO today to secure these reserves.

Now, let met just touch briefly on three issues that relate to these matters: The first is the issue of the transparency surrounding the ISO's method for determining the amount of operating reserves it requires each day.

As we all know, the Western Electricity Coordinating Council requires control areas to carry operating reserves of between five and seven percent, depending on their share of thermal and hydro resources within their resource mix.

The ISO does, in fact, procure on the order of 6.5 percent operating reserves each day. It gets those reserves through self-provision by the load-serving entities and any difference between the amount self-provided by, typically, the utilities, and the 6.5 percent requirement are acquired by the ISO through its ancillary services market.

What we have learned in recent weeks is that the operating reserve requirement that the ISO has is actually not 6.5 percent; it's something more than that. It's more on the order of ten or 12 percent.

And the reason for this is that the ISO requires additional reserves in order to cover load forecast error, and to ensure that it has an adequate supply of imbalance energy bids in real time.

We believe this issue of what the actual reserve margin requirement for the ISO is, is a critical matter that needs to be addressed.

The second item is the use of the must-offer waiver denial procedure to secure a portion of the operating reserves that represents the difference between the WTTC minimum requirement of five to seven percent and what the ISO's actual requirement is, of, say, on the order of ten to 12 percent.

As Jan mentioned in his comments, the use of the must-offer procedure is a surrogate for resource adequacy and has become increasingly controversial in recent weeks and months. And this is the case for both buyers and sellers.

When the ISO implements its Phase IB on February 1st of next year, the compensation mechanism under the must-offer procedure is going to change dramatically. Our concern is that a number of units, again, the units that are low capacity factor units that provide central reserves, are not going to be able to cover their costs under this procedure.

And we believe that the risk of this could impact resource adequacy over the next couple of years.

Finally, the ISO recently extended RMR contracts to approximately 3,000 megawatts of generation under a provision called Condition 2. But Condition 2 RMR contracts are those which operate under cost-based arrangements. They receive a cost-based payment that addresses both their fixed costs and their variable costs.

Due in part to the controversy surrounding the ISO's use of the waiver denial procedure to secure these additional operating reserves, the ISO is attempting to secure additional flexibility to use RMR Condition 2 units to provide these system reserves.

We believe this is an issue of significant concern, because it would involve the ISO using RMR units which were secured to provide local reliability services, to, in effect, now compete against uncommitted resources to provide system services.

I look forward to the opportunity during the Q&A session of our panel to touch some more on these issues. We believe that while MD02 is now moving in the right direction, it is two years away and many of the units that operate in the  market today will not survive until that timeframe.

Once again, we thank you for the opportunity to provide these comments and look forward to any questions you may have.

MR. CANNON:  We're running somewhat behind, so I will have a few minutes for some questions here.

CHAIRMAN WOOD:  Definitely.  That's a big panel.

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MR. CANNON:  Let me begin.  I've heard some slightly different messages.  Everybody talked at lot about market mitigation and market power mitigation, and resource adequacy.

Does everyone on the panel agree that it would be at least useful to know what comes out of the resource adequacy proceeding before the CPUC in advance of sort of making the next round of calls and having the next technical conference around mitigation?

Even though there seems to be some discrepancy about how strong the linkage is, I still have heard the very common theme that there is linkage there.  Comments?

MR. SMUTNEY-JONES:  Well, I think we all encourage you to operate quickly. My understanding is that your order is coming out in two weeks. I don't know how much quicker we can be.

I think it would be useful to understand what the procurement order out of the Commission will be, because that will either, a) answer some questions, or b) sharpen the focus on issues that need to be resolved or where there may be some differences of opinion.

Right now, it would be kind of an argument, and we'd be arguing about shadows. I think it would be much better for us to actually understand what the Commission is putting out there.

MR. PEEVEY: The draft will be out November 18th.

MR. SMUTNEY-JONES: Right, and, you know, after November 18th, I think the issues will be a lot crisper.

MR. CASEY: I guess, Shelton, you started by saying there seems to be agreement of the linkage between the details of the resource adequacy requirement and the market power mitigation. I guess I -- the ISO's perspective on that is that to the extent whatever the resource adequacy requirement looks like in draft form, it falls short of the elements that the ISO believes are essential to it, that the focus then needs to be how do we correct that within the resource adequacy requirement itself?

It's not our view that market power mitigation in the features of a resource adequacy requirement are a seesaw, and if one is light, you raise the other one and vice versa. It's -- if the resource adequacy requirement is deficient in meeting what we think are the stated objectives, then our focus needs to be on how do we fix it?

So, I certainly agree, you know, we're two weeks away from seeing a draft order, and we need to look at that, but the next step should not -- I'd like to move away from this issue of the market power mitigation is dependent on the features of that resource adequacy requirement.

MS. LYNCH: And I'd like to clarify. Mr. (inaudible) did state the PUC's position very clearly, and I'd just like to clarify that, because I don't think (inaudible). In fact, the PUC's position is that the must-offer requirement is a valid requirement of market-based rate authority, and, in fact, should not be linked and probably one of the biggest problems we have with the October 28 Order is that you link it and don't recognize the state's right to be free of market power, regardless of whether the resource adequacy level is that the state determined.

And by the very fact of linking it, you hand an unwarranted advantage to those who would enter into contracts with load-serving entities.

MR. CANNON: I kind of like Jim's term of complement, because it still strikes me that there is a relationship between them and that whatever package of market rules and whatever package of market mitigation tools that are put in place to protect customers, we need to work hand-in-glove with the longer-term customer protections associated with having a good resource adequacy plan.

It strikes me that there is a relationship here.

And I worry a little bit about hard-wiring one-third of the rules and saying, okay, you've got all of them right now, and let's go over and think about these other issues.

I think that's at least part of what drove some of the Commission's thinking in terms of let's not make judgments until we sort of see how these pieces work together.

CHAIRMAN WOOD: Mr. Bushnell had an interesting thought that kind of brought me back to where we are in the Midwest market design, which is kind of right pre-LMP implementation.

One of the options that we kind of asked them to tell us what they want to do, the state commissions, there's 14 that have to come to agreement, as opposed to just one and that's a little more delicate.

But there's a higher energy market cap at 5,000 with no resource adequacy requirement, but there is what we call -- I'm not sure -- narrowly constrained areas and broadly constrained areas, so there is focused local market power mitigation using the AMP tool that we've had in New York and that we have now here in California, for the local area.

And I guess what I heard you say, Dr. Bushnell, was, I guess, a recommendation that you not have an obligation to enter into long-term contracts. Maybe balance that with the price cap issue, but treat the LMPM, the local market power mitigation issue, as a separate item. Did I hear you saying that?

MR. BUSHNELL: Well, yes, more or less. The local market power mitigation mechanism does not have to be implemented in a way that, you know, a generator is just earning its marginal cost any time it's operating.

And if their bids are (inaudible) to their (inaudible) costs, it doesn't necessarily give the local price running through the LMP machinery, necessary has to reach that level.

The thing to remember about local market power mitigation resource adequacy, though, is that it's not always the case that the solution or the problem of local market power is a lack of resources. I mean, it just may not make sense to stick three generators in a given load pocket.

It may be what we consider a natural monopoly, and it just makes sense to have only one resource serving this area. And so taking the mindset that we need to apply a solution that always gives an incentive for a new entry into an area, is not necessarily going to make sense in all circumstances for local market power.

But the ISO is trying to make the distinction between bid and mitigation mechanism, which does not have to at all restrict a party's ability to recover its fixed costs, versus just the price cap.

CHAIRMAN WOOD: Good, because there is this presence of the must-offer. I mean, that kind of adds another wrinkle here. It's probably not a positive wrinkle, but the interplay of all of these is important. I think that's really what our decision is about, that there are a lot of ways you could go. You could choose not to go any way at all here at the state level like the Midwest has done, at least temporarily.

But knowing just what all the cards are on the table, it's a lot easier to figure out, you know, how to allocate the pot. So that's where we are.

But these -- talk to me from a generator perspective, Mr. Smutney-Jones, about the must-offer requirement. We've had a proposal here from the ISO that we dealt with in last week's Order, that had some thoughtful approaches there. I remember the comments of you and your colleagues. I won't characterize them as not supportive, but there were some critiques about it.

So, in light of what we've talked about today, what would you say really for the must-offer requirement, are the kind of controlling things we need to do?

MR. SMUTNEY-JONES: What is it being used for? Let me cut right to the chase, because the differences of opinion we're having here surround that very point.

We're not objecting to, you know, meaningful market rules, or, must-offer, if you will, if it's being used for basically trying to control localized market power.

I mean, there may be arguments about the details of that, but in terms of a concept, I think everyone gets that.

The problem we have is when that must-offer starts creeping into other areas and it starts looking like it's a surrogate for trying to do a resource adequacy provision, and the fact that you can phase in -- I think that was Mr. Kebler's point. You can phase in or you don't have to buy any reserves, because you're going to use the must-offer, basically, to lean on generators to provide capacity over the next couple of years.

We don't think it should be used as a surrogate, okay? And We don't believe that -- we believe that if you have a reasonable RAR issue out there, there's a procurement protocol to acquire those resources, and that that's the more appropriate place to do it.

The real debate isn't whether or not a must-offer is a good idea or bad idea, but what's it being used for?

CHAIRMAN WOOD: So you don't have a problem with it being used as the check on physical withholding concerns?

MR. BUSHNELL: Well, that's what it was designed to do.

CHAIRMAN WOOD: Correct.

MR. SMUTNEY-JONES: Right, but what our concern right now is that it's being utilized for something other than that.

CHAIRMAN WOOD: Pre-reserves?

MR. SMUTNEY-JONES: Right, and that, to us, is sort of a step too far.

CHAIRMAN WOOD: And how is the current must-offer being compensated? Aren't you given running costs and what have you? It's just that there's no fixed costs?

MR. SMUTNEY-JONES: That's correct. And the problem you have -- you run into two sort of different problems, depending on what type of generation you're looking at.

I think it clearly has a chilling effect in terms of a longer-term commitment to add new resources until there's actually a requirement that's over and above whatever is in the must-offer, so that one, I think, has already been talked about.

The second -- and I'm less certain about this, because I haven't, frankly had a direct conversation with anyone. We have a lot of old generation out there that's kind of limping along, and to the extent that they have to put new capital resources into their units just to have them around for awhile longer, you may be creating a disincentive to hang out for awhile longer.

You are probably better off boarding the thing up and hoping that some day someone comes along and buys it or the market changes and you end up turning -- getting back into modernizing the unit.

I'm less certain about that. I don't want to overstate that, but in the back of my head, I have the suspicion that there may be an unintended consequence to that. And that's why we think now is a good time -- and this is why I couched my earlier remarks around this is a very clear point that you two Commissions need to focus on.

That's why it's important that this gets addressed quickly, this RAR issue, because it is kind of where these two issues meet.

And as I said, our issue is not whether or not there needs to be meaningful market power mitigation out there, which is where our understanding of the must-offer was originally designed, but that its original purpose has mutated into something very, very different.

CHAIRMAN WOOD: I get that. Thank you. Mr. Casey?

MR. CASEY: If I could just follow up to Jan's comments and your's, Chairman Wood, about the comparability of must-offer to a resource adequacy requirement.

Fundamentally, the must-offer requirement is a tool to mitigate physical withholding. It's a very poor substitute for a resource adequacy requirement.

A resource adequacy requirement has with it, an obligation to serve California load. The must-offer requirement has no obligation for resources to serve California load. We are in a different situation this year in terms of hydro. All that generation might be exported to Arizona, and California would be scrambling to find resources, despite the must-offer agreement.

So, the critical aspect of the resource adequacy requirement is that it identifies resources committed to serving California's load.

The second is price protection through long-term contracts. The must-offer requirement doesn't have any bidding requirements on it. Resources submit whatever energy bids they want, subject to the existing market power mitigation, including AMP, but fundamentally the protection of a long-term stable contract is not there with the must-offer obligation.

So, while I'm appreciative of the concerns that Jan and Curtis have raised about how the must-offer is currently being used -- and that is something that the ISO is taking a close look at -- from a long-term perspective, we need to recognize that we can't sit back and say this must-offer obligation is all we need, because it's really not meeting the needs for a long-term, stable market.

MR. HENDRY: I would just like to follow up on one point that in September the ISO looked at must-offer waiver denials, and they received more than their operating and startup costs by about a factor of about 40 percent or about $23 million.

CHAIRMAN WOOD: Repeat that again.

MR. HENDRY: The ISO, in September of 2003, looked at must-offer waiver denials and compared the payments that they received relative to what their estimated startup and operating costs were.

And they received about 40 percent more than what their costs were estimated to be or about $23 million. So the concept that this capacity is just being bid at marginal cost with no contribution to fixed-cost recovery, I'm not sure is fully there or not.

There is a contribution toward fixed-cost recovery, and the addition of a RUC payment may increase that payment, as well, and so, again, this goes to an empirical question of what are the incentives for fixed-cost recovery for gens, and Mr. Jones has aptly described this sort of older, 50-year old units which have very highly depreciated book values, so the return on investment and the return of their variable costs need to keep competitive, may or may not be sufficient.

Again, this is an empirical question that I think the ISO had started to look at, and my comments stated that I think FERC and the PUC and others need to look at as well.

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MR. KEBLER: Could I just add a followup?

CHAIRMAN WOOD: Sure.

MR. KEBLER: I think that Jim is exactly right; there is the -- the payment structure is such that, just to use a simple example, you had a 100 megawatt unit and it had a minimum operating level of 20 megawatts. The way the compensation works is, there is something called minimum load cost compensation, which covers your startup costs and your 20 megawatts at minimum load.

You can pay an index gas price times the 20 megawatts minimum load energy. In addition to that, you do, in fact, get paid whatever the imbalance energy price is during the period in which you're operating on that 20 megawatts.

So there is not only the MLCC piece, but there's also the imbalance energy portion, which applies to that 20 megawatts. And what the Commission has said in past Orders is that -- and this goes to this issue about netting market revenues -- the Commission has said that the application of the imbalance energy price to the minimum load quantity is, in effect, intended to provide for some portion of the fixed-cost recovery.

And, Jim, you're right; it's an empirical issue about whether it covers the full amount of the fixed costs or just exactly what portion it does cover. But the intent -- and it's kind of a rough approach to apply a mechanism in this way. It is intended to provide some fixed-cost recovery.

And the point that I tried to make in my opening comment was, what happens, effective February 1, is that compensation component goes away, and so there will be literally no compensation for the reserves provided, in this example, 80 megawatts of reserves, the difference between the 20 megawatt minimum load and the operating capacity of the unit of 100 megawatts.

There will be no fixed-cost compensation and there will be only the MLCC portion.

MR. BANDERA: Can I ask one quick question for each of the panelists, really simple? Say whether you would support or tolerate, or disapprove of a market design that consisted of the market mitigation that was proposed by Cal ISO in the MD02 filing, and a market design that implemented the resource adequacy plan that is in the CPUC proceeding? So if you would just basically say whether you would support that, tolerate that, or be opposed to that?

MR. KEBLER: I'm sorry, Derek, can you repeat the question?

(Laughter.)

CHAIRMAN WOOD: The filing at the Commission, basically, plus the filing here.

COMMISSIONER BROWNELL: Both of them.

CHAIRMAN WOOD: The filing with us and the ISO's position before the CPUC.

MR. BANDERA: Right, exactly. So, if that combination of -- so it's a total view of the market, do you favor it, do you tolerate it, or do you oppose it?

MR. KEBLER: I'll answer first, so that I don't forget the question. I think that is a model that is something you could have a couple of technical conferences to work through, and see if you've struck the appropriate balance between resource adequacy and mitigation measures.

I think it's a lot closer than what the initial proposal was, which was devoid of resource adequacy and then had a very restrictive local mitigation measure.

MR. PEEVEY: Is that support or tolerate?

MR. KEBLER: That's tolerate.
MR. PEEVEY: Mr. Bushnell?
MR. BUSHNELL: I was going to think about it some more. Well, there are certainly missing elements. I don't know what's going to happen.
MR. PEEVEY: Try to answer.
MR. BUSHNELL: Well, there are certainly --
MR. BANDERA: Let's assume the customers would have to -- would remain and be obligated to fulfill the obligations as detailed by the ISO.
MR. BUSHNELL: I wouldn't be in favor of giving monthly checkups and penalizing. I would probably put myself in the bounds of tolerating. There are certainly things I'd like to change.
MR. PEEVEY: Thank you. Three words: Support, tolerate, or oppose?
(Laughter.)
MR. HENDRY: With that guide, I'll try to keep myself very short and say --
(Laughter.)
MR. HENDRY: I cannot speak for the Commission, because we haven't issued a procurement decision, and so the issue of the ISO's proposal is there. There are probably elements that the Commission could tolerate. I think there may be a lot of nuances and subissues in the ISO's proposal

that the Commission is dealing with that are live issues in the procurement proceeding on the degree of forward coverage, whether some purchases in the spot markets are tolerable, whether phase-in period and timing for it, accounting for resources.

So that's a short non-answer.

(Laughter.)

MR. SMUTNEY-JONES: Tolerate, but let's talk.

(Laughter.)

MR. CASEY: Yeah, I think the question is, everything that has --

(Laughter and discussion off the record.)

MR. CASEY: If the policy is approved, would we support it? I think the answer is yes.

(Laughter and discussion off the record.)

MR. CASEY: Should we end on that?

CHAIRMAN WOOD: No, we've got a couple more questions.

MS. LYNCH: I do think it's important to (inaudible) those proposals, both in front of FERC and front of the PUC. And while we cannot articulate a position at this point on where the ISO is, my question to the ISO is, do you include adequate resource to DWR contracts, or do you exclude them?

MR. CASEY: I think, as to the accommodation of the DWR contracts, the intent is that we would include them.

The issue with respect to the livability comes from, if these contracts are portfolio, how do you deal with deliverability?

And I think that is a challenge that we have to work through, but I don't think it's an insurmountable challenge. And I would also add that I think the contracts range in terms of their firmness of deliverability. There are some very firm contracts and then there are some as-available type contracts.

I think that in assessing the adequacy of those contracts in meeting the utility's requirements, we would have to roll up our sleeves and get into the details of the contracts.

MS. LYNCH: So are you saying that you would discount them?

MR. CASEY: I'm not saying that we would necessarily discount them; I'm just saying that the answer to that question is that we would need to better understand what the delivery obligations are under those contracts.

MS. LYNCH: I think just that one question shows the complexity of the issues regarding procurement and resource adequacy. And the next thing that we need to get into here is the issue of a state meeting its renewables mandate and how that happens over time if you immediately impose, tomorrow, a 15-percent reserve requirement in terms of what's available to be purchased, and how we can fold in this requirement, at least by -- so I do think that -- as I believe Mr. Bushnell described before, are pretty complex, and should be left the states to dig our way through -- but also some transmission issues that are inherent in these questions.

And I do think that while it's important to ask the support, tolerate, or oppose question to the panelists, you should also ask it to the utilities who are not on this panel.

CHAIRMAN WOOD: Mr. Claron, in his presentation, pointed out, and it's kind of a piggyback on Loretta's question, but does the ISO's proposal envision the capability of demand side to respond as a resource that would be contributing to the resource adequacy total?

MR. CASEY: Absolutely.

CHAIRMAN WOOD: And renewable?

MR. CASEY: Yes.

MR. HENDRY: We would say possibly. There are a number of qualifications within the ISO's proposal. There's a requirement, for example, that curtailable -- responsibility to prove they can be curtailed by being curtailed once. So, basically the industry would have to voluntarily curtail operations in order to participate in the program.

There were size limitations. They tend to want to tie it into their system resources, so they tended to require a much higher degree of metering than currently exists. We treat them more like a system resource in a way.

A lot of the smaller size limitations, which make a lot of smaller demand response programs difficult to be counted, and, again, there's a lot of details there that if you look at what was in the original ISO's ACAP proposal, would discount or eliminate a lot what the Commission was originally looking at.

That does not mean that these issues cannot be worked through, but based on what the Commission reviewed in the ISO's original ACAP proposal, we have major concerns about the treatment of demand response.

MR. CASEY: And if I could just clarify this, Chairman Wood, the specifics Jim is citing is reflecting the fact that it has to be real, and one has to, in looking at these demand programs, there has to be some verification that, yes, this is something that can actually physically perform.

And we certainly have concerns about that, but, in general, we support renewables and demand response as part of the portfolio.

CHAIRMAN WOOD: I hope that will be something y'all -- it's in your happy lap. But those details, certainly I know from across the country, that is something that's very important, and varies by region, as I think it should.

We see that it's achievable, but it just requires some attention. One last question: I heard from a couple of panelists, some concerns about residual unit commitment provisions in the MD-02 filing and our response to it. Could you all flesh that out a little more clearly for me? I'm not sure who that was from. Keith, I wrote down you, but I think someone -- Curtis, maybe you as well. Just tee it up for me. I need to understand really what the issue was.

MR. CASEY: Yeah, the ISO's proposal for residual unit commitment involved a bid-based availability payment for capacity committed in the RUC process. In effect, if capacity was ultimately dispatched in real-time, it would be rescinded.

The rationale for that particular design is that we wanted to create a level playing field with respect to incentives to bid and participate in the day-ahead energy market or be taking in the RUC process.

Our view is fundamentally that if a unit offered a bid-based offer into the day-ahead market, and it was not taken, ultimately if it's taken in RUC and dispatched based on those same bids, why does it need additional compensation?

In other words, if it had been taken in the day-ahead energy market, received the day-ahead energy price based on the market-based energy bid it submitted, or, alternatively, it was taken in real-time, based on its energy bid and received the market clearing price from that, why would it need additional compensation?

So that was the rationale for rescinding the capacity payment if the unit is dispatched. Now, the rationale for offering the capacity payment, I think gets to the issue that Curtis raised about we don't want a situation where units are sitting in real-time at minimum load, providing free operating reserve.

And to the extent that is a concern and to the extent that there is cost or value to that, the bid-based availability payment would provide a payment to compensate unit owners, if, in fact, they are not dispatched in real-time and are just sitting there.

It's a way of disciplining the ISO, as well, in the market, that, you know, you don't want to have a bunch of excess capacity sitting there in real-time, because there's a real cost with that.

The Commission altered that RUC proposal to make the RUC availability payment a market clearing price that is not rescinded, and we are concerned that under tight supply conditions where the market may not be competitive, you're setting up a situation very similar to what we experienced in our replacement reserve market back in early 2000 where a unit owner either will bypass the day-ahead energy market to be committed in the RUC process to earn both the capacity payment and an energy payment, or will bid higher in the day-ahead energy market to reflect the opportunity cost it would give up if it's taken in the energy market versus RUC.

So we have some concerns about under stress condition when market power is an issue, how allowing units to keep that availability payment will potentially lead to adverse bidding.

CHAIRMAN WOOD: So your concern was that the availability payment was taken away by the proposal?

MR. KEBLER: That's right. Under the recision provision, essentially it took the same deficiency that we have in the current must-offer mechanism where you essentially bid reserves through the application of that mechanism.

And the idea of the ISO's proposal was that this was a mitigation measure, since it was intended to avoid physical withholding. And it just comes back to this issue of an integrated market that balances all the different features.

If you have a RUC mechanism and a must-offer obligation and a resource adequacy mechanism that all can work in harmony, then that balance is achieved and you can deal with mitigation issues and still provide appropriate compensation.

But the concern that we had about the recision portion was essentially you're now -- in effect, it becomes more like a must-run obligation where the ISO has the ability to call on that resource, and can pay essentially short-run marginal costs, and there is no opportunity to recover fixed costs.

And it's particularly a problem -- and I keep coming back to this -- for the low utilization resources. If you're forward committed, you don't h ave a problem, but if you've got a low capacity factor, it really makes it difficult to recovery fixed costs anywhere in the market.

CHAIRMAN WOOD: It is difficult, but I do say, I mean, looking across the whole country, we've got the peaker issues that are just different, and we can't ignore that in the market design, either. But it's one of things that -- and I don't know if we've ever figured out the right answer yet. I'm hoping that y'all can come up with --

MR. PEEVEY: We're going to break some new ground.

(Laughter.)

CHAIRMAN WOOD: Break some new ground on that, but it is -- I mean, do y'all find that it works better in PJM where you've got facilities?

MR. KEBLER: Well, in PJM, you know, there are some issues there, but most of the capacity is forward-committed, so you've got a situation where, in a sense, the resource adequacy mechanism works in a way that the load-serving entities to a large extent, have control over the resources through their forward contracts.

And if you have that, then it's really -- that's the best way to mitigate market power, is to make the resources so that you have control over the load-serving entities through forward contracts and now all these market power mitigation issues sort of become moot because the LSCs are controlling the resources.

If I may, just one a quick comment on the previous discussion about the treatment of demand response and renewables. I thought that there were a number of good comments about the complexity of them and how we treated them.

And one example would be, if the state -- going from 20-percent renewables by 2010, a lot of those renewables are going to be intermittent. They're going to be wind and solar, and as your portfolio changes and the intermittency of the portfolio changes, you've really got to be careful about what your reserve requirement is, because it may be required to change, depending on the amount of intermittent resources of the portfolio.

CHAIRMAN WOOD: Good panel. Thanks.

(Recess.)

CHAIRMAN WOOD: Now we're on. The Chairman of the California Power Authority was not able, at the last minute, to make it, so Mr. Mike Florio has been kind enough to sub in on this panel. I know he needs no introduction. I'll turn it back over to Shelton.

MR. CANNON: Okay, our last panel is going to be looking at the issues associated with the Western grid. (Inaudible). The issue comes up, how do we make good on the promise that we made in the white paper about deferring the decision to regional state committees in the context of decisions that will be made by a single state, be it California, New York, or Florida.

And what those kinds of decisions mean in terms of their effect on neighboring states, are there needs for additional processes in terms of making sure that the decisions that do get made in California, don't have some negative impact -- begin to reconcile the decisions that may be made by its northwest or maybe southwest neighbors.

So, with that, you each have 47 seconds to --

(Laughter.)

MR. CANNON: -- explain all that. With us today, we've got Steve Greenleaf who is the Director of Regulatory Policy for the Cal ISO; we've got Don Garber, who is an attorney and Director of the Electricity Market Design Project for Sempra Energy; we have Mike Florio from -- we've got Mr. Mansour, who is the Sr. Vice President of System Operations and Asset Management for the British Columbia Commission Corporation; Barbara Hale, who is the Director of the Division of Strategic Planning with the California Public Utility Commission, and certainly not least, but Gary Ackerman, the Executive Director of the Western Power Trading Forum.

(Laughter, discussion off the record and banter.)

MR. GREENLEAF: Thanks, Shelton. Good afternoon.

I guess it's good evening for you.

President Peevey and Chairman Kissinger and other Commissioners, thanks for the opportunity to be here today.

I'll attempt, per Shelton's instructions, to keep my comments brief and largely focused on the general issues identified in the Commission's agenda.

First of all, the ISO wishes to reiterate its strong commitment to the continued and fruitful cooperation with the California Public Utilities Commission and other California state agencies in furthering what we believe to be our shared objectives of reliable and affordable electricity for the consumers of California and the rest of the West.

The ISO supports active state involvement in ISO matters that impact areas of obvious state jurisdiction and where the states have a legitimate interest in protecting consumers. To that end, and, we believe, largely consistent with the Commission's own white paper, the ISO supports active state involvement in matters such as resource adequacy, transmission, market monitoring, and the development of suitable and appropriate market power mitigation tools, rate design, demand response, load management programs, energy efficiency, environmental reviews.

On each of these matters, the ISO, and, more broadly, all RTOs, must, by necessity, work with the respective state or states to facilitate the development of truly efficient and reasonably priced wholesale electricity markets.

That being said, and respecting the significance of the ISO's commitment to continued collaboration with state agencies, the ISO, however, does not see it at this time, the pressing need to create and establish a formal regional state committee. Formal creation of such an entity, in our estimation, would entail clearly delineating between the roles, responsibilities and authority of the ISO and its governing board, the regional state committee, the state or states, and FERC, of course.

This would be no small task and may detract from the effort to develop regional consensus on important matters. We believe that when considering these issues, it's really critically important to focus on the problem at hand.

If the problem is one of state involvement in ISO development and/or ongoing operations, the ISO would argue that's really a non-issue. The state is involved, certainly in California, and the ISO does listen.

And as I said before, we are committed to the partnership that President Peevey spoke to earlier today.

If the problem is one of building regional consensus on matters impacting RTO and ISO or ISO operations, we believe the forums for addressing regional issues already exist. I think it's important when talking about regional coordination and regional committees, that we really focus on and acknowledge that only a few entities truly are empowered to act on matters that affect regional electricity markets.

Obviously, there is the Commission; there is, of course, the impacted or affected states in the region; there is also the local jurisdictional entities that oversee the municipal electric systems.

Thus, in our estimation, even if a truly regional state committee was formed, it would not be formally empowered to substantively address and resolve issues impacting regional or even subregional electricity markets.

Instead, we believe, and the ISO recommends that the Commission focus its efforts at facilitating the development or continued development of effective regional forums for addressing regional issues. In the end, it is the processes and the ideas facilitating -- and inclusive forums that will produce the consensus recommendations necessary for continued development of seamless and efficient wholesale electricity markets in the West.

While such processes and recommendations may not be binding on those participants, they nonetheless could be provided great deference in regulatory proceedings, be they at the local, state, or federal level. To that end, the ISO supports development or continuation of informal regional state committee structures such as those already in place, including the Western Governors Association, the Western Interstate Electricity Board, and its progeny, the Committee on Regional Electric Power Cooperation.

Furthermore, the ISO is committed to continued participation in such regional groups as the Seams Steering Group of the Western Interconnection and the Western Electricity Coordinating Council.

We note that just as markets avoid the uncertainty of opaque and ever-changing market rules, markets react poorly to regulatory uncertainty. At this point in time, we believe the value added from the addition of another organization or layer of review is minimal and may detract from the Commission's goal of furthering stable, seamless, and efficient markets.

In conclusion, I would just say that what really is lacking out here or what has been lacking to date, really is not a new process or a new forum or a new organization; it's leadership, and I think that certainly the Commission has stepped forward in its most recent Order, as well as has the Public Utilities Commission in looking forward and reforming the markets in California.

So, with that, I thank you for the opportunity to share our thoughts and I look forward to answering any questions you may have.

MR. CANNON: Thanks, Steve. Don?

MR. GARBER: Thank you for bringing the successful market design train to California.

(Laughter.)

MR. GARBER: And thank you especially for your well-reasoned MD02 Order that you issued last week. I think that's the best FERC Order on a California ISO matter that you have ever issued, and I think it demonstrates your thoughtfulness and your competence and a renewed sense of vigor to get the job done.

For 30 years, positive and negative influences from California have driven the FERC toward more efficient transmission pricing policies. First, in the infamous Quad Sevens case, California litigants proved that the wheeling model, with its property rights based on contract path, could be used to support a 20-year proceeding accomplishing nothing --

(Laughter.)

MR. GARBER: -- other than proving the need for new pricing rules. Largely to prevent such occurrences, the FERC opened an inquiry into transmission pricing in the mid-1980s. I remember Commissioner Stalling saying that if we can just figure out how to price transmission, the access question would take care of itself.

Well, no answers were forthcoming and that inquiry ended in failure. You roll forward a few years later and we have California seeking to introduce retail competition, actually stumbled onto the solution to the problem that had always blocked the FERC's efforts to jettison the simplistic wheeling model.

First, an independent system operator to consolidate, operationally, the balkanized grid under a standard tariff, and second, a spot market based on LMP and financial transmission rights, to price transmission service consistent with the physics of electricity.

Unfortunately, the breakthrough market design that was born in California, was not adopted for use in

California, although it was quickly adopted in the Eastern markets. Now California has an opportunity to fix its broken market and to once again make a positive contribution towards advancing the Commission's policy goals.

While reform of the ISO tariff is headed in the right direction, the process is taking too long. MD02 is now more properly called MD05, some people say MD07.

The reasons for this might be in doubt, but the slow pace is undeniable. I've got nine things that I suggest that you consider doing to finish the job:

First, I think you should establish reasonable CAISO implementation milestones and use of demand implementation filings in accordance with that schedule.

Second, you should say yes only to those elements of MD05 that you believe will support successful market design.

Three, I would urge you to negotiate an independent governance arrangement for the CAISO, rather than waiting for the D.C. Circuit to act on the case that's pending before them.

Four, I believe it is important for you to negotiate and establish formally, a division of labor between the FERC and the California Regional State Committee, but you should leave it to the California authorities to determine the composition of that Committee and how it should perform its work.

I would urge you to instruct the California ISO that focusing on market redesign to correct distorted economic incentives is likely to be more productive in reaching competitive outcomes than suppressing spot prices and layering on penalties to control behavior.

I would especially urge you to preserve sharp locational spot prices. Sharp prices are valuable things. We're spending a lot of time and effort to get them. They're needed to support efficient system operations, and they signal the need for new investment.

Price dulling, short-run market power mitigation measures are both harmful and unnecessary if effective resource adequacy measures are implemented instead. And those measures primarily should focus on financial divestment through contracts.

I think, as Curt has just mentioned, if the buyer controls the resource through contract, that market power no longer exists in the hands of the supplier.

Seven, I would urge you to protect native California load through auctions or allocation of financial transmission rights, not with preferential physical access to the grid.

Eight, I think you should allocate the costs of rate-based transmission upgrades to the California consumers that are expected to benefit from these upgrades. Mandatory socialization, which is where we are headed in California, of the cost of the grid, undermines competition.

And lastly, number nine, I think you should insist that every Western RTO use successful market design blueprints in order to ensure internal workability and external compatibility. California unfortunately has taught you not to defer to the experiments that comport neither with theory nor practice. Thank you.

MR. CANNON: Mike?

MR. FLORIO: Thank you, Shelton, thank you, Commissioners. It's a pleasure to be here. It appears that must-offer waiver was denied, so I've been dispatched into the spot market for consumer advocates.

(Laughter.)

MR. FLORIO: I think I have to second a lot of what Steve Greenleaf said about already-existing entities in the West. We have a whole alphabet soup of regional entities. We have the WECC, of course, the Western Electricity Coordinating Council; we have the Seams Steering Group of the Western Interconnection, SSGWI; we have the Western Governors Association; we have the Committee on Regional Electric Power Cooperation, CREPC; and there tend to be so many committee meetings that people go from one to another, and, unfortunately, often not very much gets done.

So I do agree with Steve that what we need are forums for getting issues resolved once and for all and not more committees meeting in more airport hotels around the West.

There are clearly some issues that reach beyond the borders of California. We're all aware of them -- transmission planning.

There are some significant efforts underway in the Southwest, the so-called step process is well along in identifying needed transmission enhancements in the area. There's a parallel process to the Northwest, which is not as far along, but there is serious work being done on this.

Could it be better? Absolutely. And we do have an interconnected system covering a huge geographic area. Unfortunately, you build a transmission line from Area A to Area B and you're likely to see benefits at one end of the line and detriments at the other end, and those create some very difficult issues that I suspect are not unique to the West, but they're -- it's very hard to get to consensus solutions on some of these.

I think that as California moves forward with resource adequacy, we're going to increasingly want to see our sister states doing the same thing. If one state or one part of the region is resource-adequate and another is not, there are going to be problems everywhere. That's certainly what we saw in 2000 and 2001 with the hydro-dependent western system, you know, one year out of ten or one year out of 15, you're going to have to find some machines to run that weren't needed in the previous nine, ten, 12 years. And that's a very difficult problem of how to maintain that capacity that's only going to be needed in a draught year, but is a problem that affects all of the West, and we need to approach it together.

Likewise, in the area of renewables, California is certainly not the only state in the West that's pressing forward on renewable development. The California Energy Commission, that didn't have a speaker here today, is putting together a database that will be not just California, but West-wide, that could become a platform for trading of renewable energy credits throughout the Western Interconnection. If we can pull that off, I think it will be a very positive step in the development of renewables throughout the Western Interconnection.

We definitely understand the need for regional market power monitoring. SSGWI has a committee that is working on developing some kind of proposal. I understand it's been fairly slow going there, but is certainly, I think, a recognition, but the institutional structure for all of these various initiatives is complex and difficult.

But at least I think, having suffered through what the West suffered through, there is a renewed sense of urgency in making these things work, but it is difficult to get to resolution when you have many different interests and many different parties weighing in with their own specific needs and points of view.

So, I think whatever the Commission can do to help the various states in the West get to resolution on some of these longstanding problems would be helpful.

MR. CANNON: Thank you, Mike.

MR. MANSOUR: Thank you, and Chairman Wood, Chairman Kissinger, Commissioner Massey, Commissioner Brownell, Commissioner Kennedy, thank your for the invitation. I realize that I'm the only non-Californian on the panel, and with that, I cannot disagree on everything, so I'm going to agree on some and not on others.

I'm glad to be here. While gathering my thoughts around the core questions put to this panel, I found myself torn between ideology and reality. I've tried my best to get them close.

Before I get to answering the question, since this is a truly one-market, I suggest RSC to be RSPC, where P stands for provinces.

(Laughter.)

MR. MANSOUR: The first two questions for this panel have to do with the scope of an RSC, and appropriateness of an single-state RSC like California. So, let me take California as the example, and maybe it's very obvious, but it's good to refer to it this great state as not self-sufficient, heavily reliant upon resources in other western states and provinces, does not possess the least-cost resources on its turf to meet its future needs, and may I remind everyone that California suffered the most in the 1996 western blackout that was triggered by events in the Northwest, not even close to the California border.

May I remind you again what the very recent blackout in the Northeast, from New York and Toronto, were blacked out with events that started in Ohio, and who in New York would have cared about 340 KV line in Ohio before the 14th of August, or who in California would have cared about anything in the state of Idaho to do with transmission before 1996?

Also, during the California crisis, I'm sure everyone remembers how painful the blackouts were. Let me share with you, some background that may not be public, but not secret.

(Laughter.)

MR. MANSOUR: Most days, the California market started the day deliveries short. My friend and his colleagues of the California ISO reach out to many of us, almost on a daily basis, whether in the day-ahead or early in the same day, to ease off the regional bottlenecks, the -- plans, and do whatever we can to minimize the impacts -- all informally.

I can assure that without personal and informal and collaborative efforts, the rotating blackout's impact on California would have been significantly worse. And with all due respect to a lot of voluntary organizations in the West, none of them is accountable for whatever I say. Who is accountable for something like during the crisis in 2001?

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Who is there now in the West who makes sure that plans for maintenance are coordinated, bottlenecks are resolved as much as they can be, and things are done in the proper way? No one.

On the planning side, yes, there is WECC; yes, there is Western Governors Association. They produce great studies. Who is accountable to make those better? No one.

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When we have many organizations like these, we should not be scared of creating one more. We should actually eliminate many of them and get one good one.

(Laughter.)

MR. MANSOUR: So, it is in California's best interests to ensure that the highway linking the East Coast resources to the state are open, reliable, and efficient. A single state committee for all the regions would not serve very well. The scope of the RST should cover the natural market as much as possible.

Now, that is ideal. Now, what is real? There's only one active and structured market in the West. That is California.

The commitment of the rest of the region varies from strong to very weak, if not opposing. FERC's platform for market design of last year or the so-called standard market design, was a great document and we can all debate, but what can be improved? But it's still a great document.

It has enough flexibility for the believer to move forward, but, unfortunately, it was never debated based on substance. Now we have the white paper. It's a lot more flexible, but without timelines, so the opposition has more grounds to drag further and the believers are frustrated. So what can we do?

Reach out to those states, commissions, utilities, groups, whatever they are who are willing to move forward, and, believe me, there are a lot of them.

We have been trying for years now to reach perfect consensus. Let us try workable consensus. This is possible.

We will not have the perfect structure, but we may have a workable one. We'll make it work and success is contagious to get the others in. But is very important to put reciprocity rules in place, that those who do not put the effort and do not participate, do not enjoy the benefits.

Formal structure is necessary to address many of those issues in the West. SSGWI is a great venue for a possible regional structure, but let us face it, SSGWI's power is derived from supposedly the power of three RTOs, two of which do not exist.

(Laughter.)

MR. MANSOUR: And they have no timeline to exist yet. Ladies and gentlemen, we will not convert those who are not already onboard, but I'm afraid to -- some who are.

Reach out. That's the message for both California and FERC.

Thank you.

MR. PEEVEY: Do I understand that you are not totally in accord with your neighbors in the state of Washington?

(Laughter.)

MR. PEEVEY: You don't have to answer.

MR. MANSOUR: I wouldn't be able to go back.

(Laughter.)

MR. CANNON: Thank you. Barbara?

MS. HALE: Thank you, Shelton, and thank you Commissioners, and welcome to California, those of you who are visiting us.

I'm Barbara Hale, Director of Strategic Planning -- PUC. I appreciate the opportunity to address you on this issue of regional state committees. Given the hour and the interest in moving things along, I'm going to make three main points and then hand the microphone over to Mr. Ackerman.

First of all, I think it's important that the state of California be regarded in this decisionmaking process as not just another stakeholder. I think the fact that the PUC and the FERC are sitting together at the dias is a clear demonstration of agreement on that point.

We have legal duties and obligations as well as a strong interest in the best interests of all Californians, and these are concerns that we have should be recognized by FERC in a regional state committee structure.

We look forward to FERC honoring the commitments to work cooperatively with the states in implementing market design, and I would say that this includes the issues which FERC's white paper looked to us, the regional state committees, to decide, but which includes addressing resource adequacy issues, allocating congestion revenue rights, engaging in transmission planning, and determining policies on participant funding.

These are key issues of interest to us. There has been a lot of dialogue about them, very constructive, I think, dialogue today about these issues, and I think a regional state committee is  good structure to help vet those through and make decisions.

The white paper pointed those issues out towards and invited a regional state committee to make decisions on them, and I would encourage you to follow through on that path.

The issue that we've heard a little bit about here today about the various groups, the Seams Working Group, the CREPC group, the Southwest Transmission Planning Expansion Group -- he's offering me his list.

(Laughter.)

MS. HALE:  Thank you.  These groups discuss and vet issues and they develop an understanding among the participants of each other's views, which I think is constructive.  But they are decidedly not decisionmaking bodies.

I think that's probably okay, but I do think there needs to be a decisionmaking body, and the FERC white paper had looked to regional state committees to be that body and I think, as I said before, I think you need to stay on that path.

Yokud very eloquently raised the issue of accountability for decisionmaking, and who do you go to?

Who do we go to when there is a problem? Who's held accountable?

I think the government links responsibility for decisionmaking and accountability in a transparent manner, and I think that should be one of the goals in establishing regional state committees. Thank you.

MR. ACKERMAN: Thank you, Shelton. Good afternoon Commissioners at the end of a long day.

(Laughter.)

MR. ACKERMAN: By going last, of course, is that everybody else makes all your important points, and so all you have to do is make citations to other folks that spoke during the day. What I like to do is give numbers for each speaker, and then when I'm all done, I get a nice list and point them off one-by-one.

But earlier this year, I sat with my members in the Northwest as I do every other month, and I was shocked to find out that the Northwest Power Planning Council, which everybody knows, by federal statute, must come out with supply/demand balance, publicly stated that it is not accountable for resource adequacy in the Northwest.

Furthermore, since 1992, the Bonneville Power Administration has decided that it's not going to build new resources to meet the growing load or the growing needs of its public utility district customers. And then we got to the Southwest where it's much more generation, at least new generation being sited relative to the load that's in that part of the region, and the question of resource adequacy isn't even seriously asked, in my opinion.

And then we get to my favorite state, my home state, California, where the ISO and state agencies are attempting to develop a resource adequacy program, and I know we've heard a lot of comments about how we're getting very close to a decision in two weeks. But, you know, I've been in this state for over 20 years. I've watched the PUC for at least that amount of time, and I even remember Paul Plane explained to me once that when the PUC makes decisions, what it really is doing is like a big ship in the water. It kinds of turns in the general direction of where it wants to go, eventually getting there, but makes no waves. It just goes zip on the spot and finds its bearings.

And I don't think this next decision that's about to be issued is going to be the end-all and the be-all with respect to resource adequacy -- far from it. There will be a lot of unanswered questions.

My group, which includes both generators and energy service providers, have been banging their heads together, trying to figure out what does resource adequacy mean? We haven't figured it out. We've been trying.

And just looking at the record and the testimony that's been given in that particular proceeding, I think it's more fair to characterize it as a proceeding on procurement which leads to resource adequacy, but isn't necessarily going to define and be the last word in resource adequacy.

So, what was said earlier, I fully agree across the whole region, that there really, quite frankly, is no one accountable for resource adequacy across the western states.

Now, you folks know that this is a serious problem. There is no one in this room who doesn't understand it, but it bears repeating and was mentioned, I thought, aptly by Susan Kennedy earlier in the day with her comment that time is no friend for us.

Californians know or must know that the future of their electric system is in a delicate balance right now, and that's with a normal hydro year, and might be threatened in a few short years. In my opinion, this is no problem that one state in the region can solve independently. Now, here's why:

The region is faced with shortages when rain or snowpack in the Northwest, for example, do not materialize.

When the hydro generation is low, we know that the swing capacity that makes up the difference must be -- it's not can be -- must be gas-fired generation in California and the

Southwest.

And when that happens, of course, demand is increased and all the users of natural gas, of course, people who heat their homes and cook their foods, as well as generation stations that have to produce the electricity to make up for that hydro shortage, are going to be looking at higher costs for natural gas. It has an impact.

And that's how it works in this region, and it doesn't work that way every year. We don't know, nor can we predict, when we're not going to have an average or above-average hydro year, but we know for sure that every so often, it's going to occur. It occurred in spades in 2000 and 2001. It was graphically demonstrated then and the lesson was pounded upon us.

So I think if you want to give an acid test to any resource adequacy program, just ask yourself, would it withstand a hydro shortage of a duration of weeks and months? See, in the West, unlike the East, Midwest, Southwest, or Texas, we don't have shortages that last an hour or a week or a month; it's due to the fact that there's insufficient hydro resources, and that lasts many months, even up to a year or a year and a half.

A regional state committee, I believe, has the possibility of taking ownership of this dilemma and wouldn't supplant nor replace what the states must do individually.

It would have to work in concert, obviously, with what the Public Utilities Commission is doing.

But I want you to keep in mind that at the height of the energy crisis, the capacity reserve margin for the western states was 14.5 percent. That's at the height of the Winter of 2001.

Tell me, what do we achieve when we mandate that all load-serving entities should have 15 percent or thereabouts reserve margins? What do we really accomplish?

Do we really set up the rules to avoid bad outcomes that occur when we have a shortage in the West?

I would think that a regional state committee that works with all states could set standards on how to count resources, because we don't even have that yet. That's a tough problem, how to count resources. You touched on it in your last panel.

You asked the question or some of you asked the question, how would renewable resources be counted? How would hydro resources be counted, and how would intermittent resources be counted?

Well, we don't know; we don't have a standard. We don't have it in California. It's a tough enough question just for that, but we need standards for the entire region so that we know whether or not we have sufficient resources to meet the Western demand.  We don't even know that, so we can't even answer that simple question.

If a regional state committee were responsible for supply adequacy, then it could advise states such as California. And here's where I agree with Mike Florio.

(Laughter.)

MR. FLORIO: You're making so much sense.

(Laughter, discussion off the record, and banter.)

MR. ACKERMAN: I love that guy, really. All right, here we go.

You have those units that are sitting around, at least with low capacity factors. You've heard all the operating problems with low-capacity units, but that is our best insurance policy in the state of California.

Will we come up with that answer if we just try and resolve resource adequacy on our own? I'm not sure. I won't say no and I won't say yes. I have to see what the PUC is planning on doing, but it seems to me that anybody looking at this from a regional point of view, would say, you know, those old units that are idle most of the time, but operate 15, 20, 25 percent of the time? They have value in terms of capacity.

And it doesn't make any sense for new and efficient power plants to sit idle most of the year, year after year, waiting for the right conditions to operate.

You know no private investor is going to take that up, and it makes no sense for a utility to build under those conditions, as well, because why? That means their ratepayers have to pick up for a resource that's idle.

All we would be doing is over-building the generation infrastructure in the state of California, driving down the value of energy markets in order to satisfy capacity. It makes no sense.

So there needs to be a mechanism that incents owners of the aging power plants to keep their assets ready during periods of hydro surplus, and the traditional reserve marginal requirement won't get us there.

Now, in closing, a regional state committee under FERC jurisdiction, I believe, would help avoid over-investment in power generation. I believe it would also balance the needs of transmission upgrades and additions, and provide a single voice to FERC on market monitoring.

Now, we're not against having market monitoring alternate in some part of the region, but we'd like to have one voice on market monitoring reporting to the Commission, the Federal Commission, in terms of what's appropriate, inappropriate, and how people who abuse the system will be taken to task.

So, we look forward to making that a reality, and I would like to answer any questions you might have.

COMMISSIONER KENNEDY: Thank you. I do have questions. I got a little lost in terms of whether you said that a regional committee is a good thing. We need that, right?

MR. ACKERMAN: I'm sorry?

COMMISSIONER KENNEDY: You're saying that we don't need one right now, and I'm not sure what I heard from you guys. We need one? We don't need one? I think I heard you say yes.

MR. MANSOUR: Well that is more --

COMMISSIONER KENNEDY: Yes, okay. We didn't really get into some of the core questions of jurisdiction.

I mean, I was struck by Mr. Greenleaf's initial comments about the proper jurisdictions.

California is exploring the notion of having a California-only RSC and having the state PUC be that regional state committee. We don't have jurisdiction over the munies. Do you see a problem with that?

I'm not quite sure how we would construct this, and I'm not sure what the -- so I'd like to have a little bit more discussion about the jurisdictional issues and what you think of the notion of the PUC Commissioners. As I understand it, the other models involve the state commissioners in other states, but it's a multi-state entity.

Well, do they have the same jurisdictional problems we do with municipal entities in your states, or do they not? Is that unique to California? I'm wondering how they bridge that gap? Take your best shot.

MR. GARBER: Let me take a shot at it. We would actually prefer a one RTO for the West, one market monitor for the West, one RCS for the West, but we just -- my company doesn't believe that that is feasible for the next few years, and so we would like to see California go forward and hopefully the other two RTOs will form, but they may not. I don't know if FERC has the authority to force them to form or not.

If California is going to go for it and have a market just of California resources, then we think the RSC should be congruent with that footprint, and how it's composed, I think that our view is that this is something for California authorities, not just the PUC to decide, but all of the California authorities to decide.

It may well be that the PUC is the entity, but it seems to me that that is something that everyone in California that has some authority to have an opinion about that, ought to weigh in, but it's primarily something that FERC should not try to decide, and similarly, with the duties.

We believe that if the RSC came forward with their white paper on the duties, I think that needs to be sharpened up some. I think there needs to probably be some kind of give-and-take between the RSC and the FERC as to what this committee should do.

But from the standpoint of -- my company is regulated by both the PUC and the FERC and we suffer if those two elephants are not in sync as to what they are doing and how they do it. We want to be able to serve our masters and not be in a conflict.

So we would prefer that you negotiate a division of labor, get it set that FERC does certain things, California authorities do the other things that complement, and that there's agreement about that.

MR. GREENLEAF: I would just comment that, taking them separately, with respect to California, clearly we have been and remain committed to working with the PUC and other state agencies on matters that affect the wholesale electricity market.

The issue for us is with respect to the RSC, and going back to the white paper, some of the duties that you envision -- that FERC envisions for the RSC, include allocation where you heard earlier today, just fundamentally what a critical issue that is.

And with respect to the CPUC oversight over the allocation of CRRs for the investor-owned utilities in California is appropriate, understandable, and a steward to the load in California. But, you know, I think we all clearly acknowledge that municipals represent a large amount of load. You have direct access load.

Those issues need to be resolved, and it could entail -- it could be accomplished, perhaps, through the creation of some kind of committee structure under the RSC, as guided by the PUC, but in our estimation, that just creates a very complicated governance structure that potentially could stop us from gaining meaningful resolution of the issues in California.

On a broader regional basis, let me just say that

I think we support -- we would love to have an RSC -- an empowered -- that's an important qualification -- who's accountable, an empowered RSC for the entire West. I just don't see it at this point. I don't see any of the states, certainly, right now giving up or ceding jurisdiction or even deference to a larger regional body.

So I support the ideal and the vision, but right now, I'm just driven and I think we are driven by the practical reality that is we don't just see some institutions coming together any time soon.

MR. ACKERMAN: You know, I think that Steve points to something that is different than what I was talking about. I think a regional state committee should only have a limited scope and purpose. And beyond that, it doesn't make a lot of sense.

For example, I don't think a regional state committee has any business whatsoever telling the state how CRR allocation versus auction should take place. That's one example where I think it's purely within the state, and you can't make a good reasonable case as to why that's an item which crosses the state boundary.

Whereas, for resource adequacy, in terms of counting resources and what the penalties would be and advising states accordingly, there I think you can make that argument. So I am not envisioning a regional state commission as one that helps solve issues. God knows, we have enough organizations that have been alluded to here in other people's talks about organizations that, you know, get together every month and meet in the airport hotel rooms and whatever they do.

And they try and resolve issues. I don't care about issues. We're over that. We need some results here, and I've got to tell you, the two things that I don't think we're going to see between now and the next major shortage in the West: We're not going to see tradable capacity markets and we're not going to see a regional state committee. I'm sorry to say that. It's a sad comment, but I think it's just the way thing are going to be.

And maybe when it happens again, we'll just either a) we'll have been doing a lot of due diligence and get there, or, b) maybe we'll just pick up the ball and get serious.

MS. HALE: If I could, Commissioner Kennedy, you asked about other experiences, and it's my understanding that there are no other single state regional state committees. California, being, in and of itself, the ISO, I think it makes sense for now to have a regional state committee that has the same footprint. I'm not sure who used that terminology, but I like that.

The idea of having the various discussion groups, these other regional groups, give input that the regional state committee, if it's the PUC or some version of a regional state committee that's California-only, that takes advantage of that discussion and benefits from that discussion, I think is useful.

If we have no regional state committee, as was described, contrary to the FERC white paper, if we have no regional state committee, then I think these issues are just -- I think these issues, Steve, are decided largely by an ISO filing to FERC without the overlay and input of the Public Utilities Commission or the regional state committee of whatever form it is.

The FERC white paper invited that. I think that's an important step for that broader state perspective to be brought into that thinking, and I think the regional state committee, for now, if it matches the footprint of the California ISO, makes a lot of sense.

MR. MANSOUR: First of all, I understand that under the RSC structures, the states will give up their jurisdiction to the RSC. I think that's the case and I think they mean that that's the case.

Every state has its own -- to retain its own jurisdiction and its own authority. These are representative of the states in a committee to make decisions that represents all views of the states.

And again, we're not talking again about one RTO.

This is, again, a very contentious piece, and we're talking about something as one, two, three -- one market, two jurisdictions, and three RTOs.

MR. FLORIO: On the issue of a California-specific RSC, I think we do need to address somehow, the needs and the interests of the municipals, because if this WAPPA control area goes forward, we're looking at, you know, a splintering in California beyond -- you know, we talk about the hole in the donut of the ISO now. There's no donut left if that goes forward.

So we really, I think, are badly in need of a forum in which both representatives of the CPUC and of the municipals can try to work through some of these problems together, because my worry, if we have a RSC that is just the Commission overseeing the investor-owned utilities, is that there will be a sense among the municipals of, well, this isn't for us; we need to go somewhere else, and we could end up with even more problems than we've got now.

COMMISSIONER KENNEDY: I don't see that as possible. They can't function. This is not just about the control areas.

Use transmission planning as an example. That's one of the duties of the regional state committee, but the regionals -- if the Commission is doing it, the state PUC as the regional state committee does transmission planning and the ISO does the needs determination and then it comes back to the PUC for the CPCN permit, that would be fun, actually.

(Laughter.)

COMMISSIONER KENNEDY: We can delay it for 20 years.

(Laughter.)

COMMISSIONER KENNEDY: Does anybody want to have a shot on how that would work? Mr. Gallagher, maybe?

(Laughter.)

MR. GALLAGHER: Thanks. Thank you for that question, Commissioner.

I think there are a lot of implementation issue as to how an RCS would actually operate, and you raised some of the most important ones. I don't think I can give you a clearer answer than that right now.

I think we all recognize that, going forward, if there is going to be an RSC in California, we have to figure out who it is going to be composed of, how it's going to carry out its duties, if it's the Commission, how those duties will be, how those duties will correspond to the Commission's traditional or normal statutory duties. Those are the questions that have to be answered.

CHAIRMAN WOOD: Here's a thought: In the Midwest and in New England, they both have pretty strong -- and

ERCOT as well -- the ISO and the professionals on that staff assess the needs of the system, just on a pure needs basis every year and propose a formal plan that's ratified by their board.

At that point, they can either allocate to specific utilities, their responsibility to build, or put it out for just an all-source solicitation that we've got the need to increase transfer capacity between A and B. We don't know whose farm that goes through; we don't even know if it's a transmission solution, but we've got needs here where the grid is weak.

And so they could do that in a number of different scenarios. Any of those scenarios will require approval from a state commission or some sort of state approval. Then what they've set up in the 14-state MISO group is, they get the plan, and if it's a transmission solution that's needed, which are what they've gotten, probably about $1.6 billion, I think, worth of recommended transmission construction, then if it's over three states, those three states will peel off and do a common proceeding together to try to get that approved in an expeditious manner, or at least review for approval in an expeditious manner.

If it's one state, then that one state handles it like they always did, but you've got a body looking after the health of the whole grid, saying we need something here.

Okay, state commissioners, you guys have to do the approval and then we've got a utility or maybe a merchant provider --

COMMISSIONER KENNEDY: I think it's very different being a multi-state entity than it is a single state. We divided three/two over the energy action plan because we were accused of prejudging the transmission, so we're going to have to come to -- we wouldn't be in a position to make a judgment about any kind of need, unless we were looking at it on a multi-state basis.

Now, I hear Mr. Ackerman on both counts, that it's needed and it probably ain't going to happen.

CHAIRMAN WOOD: What about transmission between here and Arizona? I mean, how does the Southwest work? Robert, are you working with that, or Shawn or anybody else?

Steve?

MS. HALE: Well, the PUC staff are engaged in the STEP process, and as I understand it, that out of the STEP process will come an ISO staff recommendation to the ISO Board along the lines that you just described, Chairman Wood, where they will say, all right, here's the alternatives and say, okay, you know, you've got one of the alternatives. I'm speaking hypothetically now.

SDG&E, you have an alternative, and if it's an alternative that's going to be pursued, it comes to the PUC.

But if it's an alternative that would be pursued by Imperial Irrigation District or other non-PUC entity, it's not going to come to the PUC.

As I understand it, any of the alternatives that would potentially come to the PUC, we may need, the PUC may need to make overtures to our neighbors across the border to have a dialogue and understanding of what the impacts are.

Whether the existing regional dialogues already provide that information to us, I'm not sure on, but those are clearly not decisionmaking bodies, but could be useful input to us as we go forward. If we want to make that a more formalized relationship where the PUC needs the input of the utility commissions in our neighboring states, we could certainly do that in the sort of joint approach that you just described happens, Chairman Wood, in other states.

CHAIRMAN WOOD: Is WECC actually taking on that responsibility of doing West-wide planning? I know they have been talking about it since I have been here, but is that actually going on?

MR. ACKERMAN: They do it in transmission assessment.

MR. GREENLEAF: Well, let me just say -- well, I'm certainly no expert. WECC does coordinated transmission planning for the West, with a focus on reliability metering projects. I don't want to -- I think the recent SSGWI effort was significant. There was an effort on transmission planning for the entire West with a focus on economic projects.

CHAIRMAN WOOD: Was this the filing that we got yesterday, Shelton?

MR. CANNON: Yes.

MR. GREENLEAF: But it really gets down to the issues Barbara raised. While it identifies the need and there is some regional consensus on the need for certain economic transmission projects throughout the West, but the problem is, how do you get them built?

And how do you address the needs? And, to date, there is no organization, nor is there a structure for the states coming together and approving those collectively.

MR. ACKERMAN: And allocating costs.

MR. GREENLEAF: And allocating costs.

COMMISSIONER MASSEY: May I ask a question at this point? What is the role of the FERC in empowering a broader regional organization? Should we be thinking about that, or should we simply be focusing on the state of California at this point because it's the only one that's real?

My own view is that none of these problems are going to be solved in a way that really sticks, in a way that endures long-term without broader regional solutions.

MR. ACKERMAN: I believe that the FERC is the only body that can really authorize and empower the type of regional state committee which has limited authority do certain things, which coordinates on very specific items and reports to the Commission. I think that would be the only way possible.

Now, that means you have to do battle with all your good friends from the Northwest delegation --

(Laughter.)

MR. ACKERMAN: But I guess my question is, if you don't start now, when are you going to start?

MR. PEEVEY: How can -- it seems to me we worry about that. We have to, you know, take care of our knitting right here at home. I don't understand how -- I mean, the situation seems to just be getting worse and worse. And it's really sub-optimal.

How do you plan adequately? We heard this morning about how the grid is not maximized in many respects. How do we truly plan for something that's 60-percent IOU and 40-percent municipal?

I'm sorry to say this, but without the municipals being in the ISO, I mean, how in the hell do you do it?

MR. ACKERMAN: Don't we have to supersede the boundaries of the ISO to answer your question? I mean, didn't you answer your own question?

CHAIRMAN WOOD: But under what statute?

MR. PEEVEY: I'm not asking the question, actually. This is more rhetorical, frankly.

(Laughter.)

MR. ACKERMAN: That was a rhetorical answer.

(Laughter.)

MR. PEEVEY: You're very good at that. Whether it's RPS or whether it's transmission planning or renewables, or what have you, we expect the IOUs to do it all, essentially, in California. And it seems disproportionate, disjointed, and yet we've got the municipals, some of them, very actively hoping that we create another control group.

We've got SMUD with its own control group now, and now we've got WAPA wanting to do this, with the support of several of the Northern California municipals, which is just a further balkanization, and it seems to me that it's going the exact opposite from what rationality would suggest we do.

CHAIRMAN WOOD: I will say that I think the control area debate was dramatically changed in the country on August the 14th.

MR. PEEVEY: Well, it hasn't seeped into California.

(Laughter.)

CHAIRMAN WOOD: You handle that.

MR. ACKERMAN: But to handle your rhetorical question, I mean, people in the Northwest say the very same thing. They just replace the words, investor-owned with BPA.

And they ask the very same question that you just asked, so it seems to me that the answer lends itself to what I was telling Commissioner Massey, which is that without the Federal Energy Regulatory Commission doing that, I don't see it.

MR. PEEVEY: But they can't do anything about the munies in California.

MR. MANSOUR: Commissioner Massey, first of all, I really find -- frustration. Many meetings we go to, you know, like this one, not this meeting, because this meeting is great.

(Laughter.)

COMMISSIONER BROWNELL: Nice save, Yokout.

(Laughter.)

CHAIRMAN WOOD: You get the M&M.

MR. MANSOUR: But we sit down and admit and recognize we have problems. We have issues; we have major issues that we all recognize. And we also realize that there is no one at the time being, no group at the time being, that is accountable for doing it.

And then at the end we say, but it's also impossible to find a group and let's go home. It can't be, it just can't be. This is the best country on earth, and it can't be that we have the problem.

(Laughter.)

MR. PEEVEY: Are we talking about Canada or the United States?

(Laughter.)

MR. MANSOUR: You put me on the spot. But we just can't accept that. We cannot accept that, and more than we, you should not accept that.

Now, when people say -- again, back to what I was saying in my remarks. When people say it's impossible, yes, it is impossible to bring everyone, but it is not impossible to bring enough. It will take effort, it will take leadership, but bring those who are willing to move, number one.

Number two, there will have to be a clear distinction between those join and enjoy the benefit and those who don't. If that is not there, there will be no incentive for others to come along. We'll get there slower, but surely.

COMMISSIONER KENNEDY: Is he a motivational speaker in his free time?

(Laughter.)

CHAIRMAN WOOD: He must have been. I think it was two years ago last week that we met t his gentleman in Seattle for the first time. And, gosh, it seems like RTO West was farther along then than it is now.

(Laughter.)

MR. MANSOUR: Actually, if you want to see where we are exactly, you just monitor the NASDAQ Index. We are about 20 percent ahead of where we were six months ago and about 25 percent behind where we were two and a half years ago.

(Laughter.)

CHAIRMAN WOOD: Let me ask a more granular question. I heard it come up with the contrasts between what Don said and the issue that Barbara flagged up, and that's participant funding or how to pay for new transmission expansions.

Siting is a hard problem. We don't even get there if the utility has no clue about how it's going to get its money back. This issue has been probably the barn-burner issue for us, surprisingly, in New York where we had one of these two weeks ago.

And it was not a surprisingly big issue for us when we did one of these in Atlanta.

(Laughter.)

CHAIRMAN WOOD: And the outcome and the strong advocacy was identical in both markets, which I think, for me, at least, was a surprise. It's one of the issues we're asking the states to do, and we had a single state forum in New York and Florida. Florida is actually kind of pre-RTO/ISO world, but they're wanting to do all these things as well, and we came out pretty strong saying, yes, certainly the big four resource advocacy -- how do you want to do it or which way do you want to do it, if at all? How to allocate congestion revenue rights or FTRs, but that issue kind of shows up when you're a lot more mature market like this one; transmission planning, the role of the interplay between the state authorities and the ISO, is certainly a big one, and then how do you pay for transmission? We just call that PF for participant funding issues. How do you actually do that?

That I something that I know there's a full plate for you guys with, but, Steve, could you just give us a quick rundown about how that's actually paid for under the current practice? Is it in each of the three IOUs?

MR. GREENLEAF: Well, my colleague to the left --

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CHAIRMAN WOOD: Okay, whoever is the best.

MR. GREENLEAF: Right now, as I understand it, yes, we have a combination of the license plate approach and a grid-wide, California ISO grid-wide approach wherein existing investment, embedded costs of the system were paid by the access charges applicable to the existing PTOs.

New investment, however, and also, I think, with a ten-year rollover, is going towards a grid-wide rate. So under the existing ISO TAC construct, any new transmission line over 200 gets rolled in grid-wide, and then existing transmission that's over 200 is being phased in over a ten-year period to a grid-wide. I hope that helps.

CHAIRMAN WOOD: And did I hear, Don, that you have a problem with that?

MR. GARBER: Yeah, I've got a problem with that.

(Laughter.)

MR. GARBER: I think the Commission --

CHAIRMAN WOOD: You get your money back either way, so you care, why?

MR. GARBER: Well, the Commission has been getting into this problem and making this mistake for a long time now. It goes back to your song about everyone is someone's native load customer, and therefore, let's just all roll it in, we're all Americans, transmission is only five or ten percent of the total, so why are we sweating this? We can't figure out how to allocate costs, it's making our heads hurt, so let's just get on with building it and socializing it.

CHAIRMAN WOOD: That's my speech.

(Laughter.)

MR. GARBER: And this went on for decades, and it was linked to the fact that you didn't know how to price transmission, didn't have any locational aspect to transmission pricing. You had this contract path fiction.

And like so many things, you know, California got a hold of this three or four years ago, before you started getting religion about participant funding, before it provoked a near-death experience on the Hill, and yet we're now stuck with it.

The rest of the country is moving, say, in license plate or some form of modified license plate, which allows a judgment to be made about how new expansions of the grid ought to be allocated over broad areas. We're now stuck in California with a mandatory allocation. Everything must be socialized, regardless of what effect it has anywhere on the California grid.

Now, it's going to take a few years to roll in, but the die is cast, and that issue is not rethought, because it was made in 2000, I suppose, and it's now down in the hearing room and the judge thinks that she has no authority to do anything other than go with the postage stamp, mandatory socialization.

So I think that's a problem for us in California.

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I don't put that at the top of the list, and it's possible that since we're all Californians, maybe, you know, state authorities would say, well, it's not so bad for us, because we are all under one state, and we want northern and southern California to all be socialized.

But I think it dulls the incentives, it distorts the incentives, and it's going to give incentives for people to oppose projects, because they are going to say, look, I'm getting 40 percent of it allocated to me, and I don't think any of the benefits are coming my way.

So, it's going to set off all sorts of gaming and tactical positions to be taken in siting responsibilities. You know, you don't have to allocate anything anymore, but people look at the allocation, the implicit, the mandatory allocation issue, and they say, I'm going to go in and fight that in the siting process, because I think it just adds to costs for my consumers and no benefits.

So I urge you to rethink that. And California, the RSC, they ought to revisit that issue and decide whether or not, affirmatively, yes, we believe it's better to have just one price for all of California, because we're one state, or, no, maybe we ought to have the historic three zones or if communities came on, maybe four zones for the cost.

CHAIRMAN WOOD: I will just say that's in the white paper, and we mean what we say, that it's an issue that we want to defer to the state authorities. It's a cost allocation, an equities issue, and it would be better to ask that than folks that have to live here.

But that is the one that, Barbara, you ticked off before. I would say that's one of the four we hadn't talked about yet.

I just want to say that on behalf of us, we would certainly invite you all to do that, and tell us if that's where you want to be or you don't want to be. But it doesn't have to be the same in every state.

But we did hear pretty clearly in New York that it becomes hard to reconcile a more socialized form of economic upgrades, reliability upgrades, probably for a different purpose with an LMP market. It really starts to bust up a lot of the expectations there on investment.

I'm a late comer to understanding it, you know, coming out of the fortress of ERCOT where you could keep all the costs and all the benefits behind the wall. It was pretty easy to spread it, but it's harder to do here. So, I'll throw one more to your plate, Mr. President.

MR. PEEVEY: Thanks. Given the lateness of the hour, I think I'll strike out.

CHAIRMAN WOOD: Good. Thank you all today. I want to thank our staff. Let me just introduce, for the benefit of the California parties here, Shelton Cannon, of course; Jason Shipley gave a presentation; David Perlman is with our Office of General Counsel, Derek Bandera, from our Office of Markets, Tariffs and Rates, an economist, Jamie Simler, who is head of the Western Division issues, all gas and electric out here, and Rob Gramlich from our Office, Len Tao from General Counsel's Office, Susan Pollonaise from Markets, Tariffs, and Rates-West; Bud Earley from our Commissioner Massey's Office; Charlie Whitmore from our Office of Market Oversight and Investigation; Charles Faust is our representative out here at the Cal ISO, so he's full-time out here, and we appreciate your being here, Charles. The tour of duty ain't so bad out here.

(Laughter.)

CHAIRMAN WOOD: And I want to thank Sarah McKinley for her coordination, and Brian Lee, from our Office of External Affairs.

Again, I want to thank our dear hosts. We enjoyed the friendship and look forward to more collaboration. Y'all are extremely important to this country, as you all know, and to the economy, but we care a lot on the personal level, too, because of what we've had to go through in our job, and we want to support the efforts y'all are doing, and you fine staff.

MR. PEEVEY: You have our commitment to work as strenuously as we can with you to make things work.

CHAIRMAN WOOD: Meeting adjourned. Thank you very much.

(Applause.)

(Whereupon, at 5:50 p.m., the technical conference was concluded.)