JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2008	)	Docket No.
Integrated Energy Policy Report	)	08-IEP-1B
Update and the 2009 Integrated	)	
Energy Policy Report	)	
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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SACRAMENTO, CALIFORNIA

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COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, Integrated Energy Policy Report Committee

Jackalyne Pfannenstiel, Associate Member, Integrated Energy Policy Report Committee

Karen Douglas, Presiding Member, Renewables Committee

ADVISORS PRESENT

Panama Bartholomy

Laurie Ten Hope

Tim Tutt

STAFF and CONTRACTORS PRESENT

Jim Bartridge

Pam Doughman (via telephone)

Suzanne Korosec

Donna Parrow

ALSO PRESENT

Steve Sorey, Sacramento Municipal Utility District

Mukhles Bhuiyan, Los Angeles Department of Water and Power

Juan Carlos Sandoval, Imperial Irrigation District

Randy Baysinger, Turlock Irrigation District

Laura Manz, California Independent System Operator

Karen Edson, California Independent System Operator

Roy Kuga, Pacific Gas and Electric Company

Edward Cazalet, PhD, MegaWatt Storage Farms, Inc.

C. Anthony Braun, Braun Blaising McLaughlin on behalf of California Municipal Utilities Association

Manuel Alvarez, Southern California Edison

Victor Kruger, San Diego Gas and Electric

Steven Kelly, Independent Energy Producers Association

Craig Lewis, GreenVolts

Tandy McMannes, Abengoa Solar

Nancy Rader, California Wind Energy Association

Jeffery D. Harris, Ellison Schneider & Harris on behalf of Bright Source Energy

Anne Gillette, California Public Utilities Commission

Arthur O'Donnell, Center for Resource Solutions (via telephone)

Joseph Langenberg, Central California Power (via telephone)

I N D E X

P R O C E E D I N G S

1:07 p.m.

PRESIDING MEMBER BYRON: Good afternoon, everyone, and thank you for being here. Welcome to a Joint Committee Workshop of the Integrated Energy Policy Report Committee and the Renewable Committee.

I'm Jeff Byron. And to my left is the Associate Member of the IEPR Committee, and that is our Chairman Pfannenstiel. And to my right is a member of the Renewables Committee, Chairman Douglas. Further to my left is Chairman Pfannenstiel's Advisor, Tim Tutt. All the way to the left is Panama Bartholomy, Commissioner Douglas' Advisor. And I can't see her but my Advisor, Laurie, is to my right. Laurie Ten Hope.

If it is okay, Suzanne, I was just going to introduce just a couple of things before I turn it over to you.

This is a Committee Workshop that really is the follow-on of three earlier staff workshops that were conducted on this subject. And I just want to reiterate what we are doing here. The goal of this workshop is to determine what analysis is needed to identify and evaluate the major hurdles for obtaining higher levels of renewables in California.

Suzanne is going to take us through those earlier workshops and what they covered. But we have identified this in the IEPR Committee as an extremely important topic on how the 2020 electricity system needs to be restructured to accommodate higher levels of renewables.

And this is going to continue to become a more important topic, I think, as we move forward. I just learned this morning that one of my fellow Commissioners participated in a press conference on this topic and hopefully she will say something about it in a moment.

But we are going to be here for the afternoon and consolidate a lot of the information that we have picked up in previous workshops. I have a number of public comment cards already and we look forward to input from old friends and others here. I also notice we have a former member of the ISO Board here that will speak later, Mr. Cazalet.

I turn to my fellow Commissioners and see if they would like to say anything as well.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks

Jeff. I'm glad people are here to help us with this thorny issue. As everybody here I think knows, the Energy Commission has several times in the past advocated for 33 percent RPS. And every time we do so we get some push-back about can it be done, should it be done, what is needed.

So in the IEPR process we have finally decided that we just needed to hear from people very directly, what are the problems. And the three that we have held prior workshops on were system integration, technology development and transmission. So we will clearly spend time today on all of these.

But I am going to urge people to come in with a mind set that the Energy Commission really believes that we not only should but can get to 33 percent renewables. And so we are left at this point interested in identifying the barriers and identifying how to overcome to barriers. And whether it is a technology development next step or, in fact, is it legislation? What do we need to overcome each one of the obstacles that people have put in the way.

It looks like an interesting afternoon. I hope people don't have dinner plans because it may go long.

PRESIDING MEMBER BYRON: I do.

COMMISSIONER DOUGLAS: Good afternoon. Again, I am Commissioner Douglas. I am the Presiding Member of the Renewables Committee. I am very happy to be here at this Joint IEPR and Renewables Committee Workshop on achieving higher levels of renewable energy.

I am happy to see so many people here. Pleased that we are able to be joined by CPUC and ISO staff and representatives from utilities and other stakeholders.

As Commissioner Byron mentioned, I was asked by the Governor's Office to attend a press conference this morning on 33 percent renewables and did so. As I said there and I will repeat here for the benefit of this audience, the goal of the administration is to achieve at least 33 percent of the state's electricity from renewable sources by 2020. And the issue for us at this point is, how do we do it and how do we do it in a way that makes sense.

It is not enough to just raise the number in the statute, although it is an important step to raise the number in the statute. We need to develop, working with stakeholders and other government agencies, we need to develop the appropriate package of policy reforms that will help us get on track and stay on track for meeting these targets, while meeting our other very important goals in the electricity sector, such as delivering reliable and affordable power to Californians.

So I am very pleased to be here and very much look forward to hearing from the speakers and also from the public. Thank you.

PRESIDING MEMBER BYRON: Thank you, Commissioners.

Ms. Korosec, I turn this over to your capable hands. Perform your magic, please.

MS. KOROSEC: Well, gosh, don't raise expectations too high please. I am Suzanne Korosec, I am leading the IEPR effort this cycle.

Just a few housekeeping items before we get started. For those of you who have not been in the building before, the restrooms are out the double doors and to your left. There is a snack room on the second floor of the atrium under the white awning. And if we do have an emergency and have to evacuate the building please follow the staff out the door to the park across the street and we will wait for the all-clear signal.

Today's workshop is being webcast. And for those who are listening in who may wish to speak during the public comment period the number is 888-566-5914 and the passcode is I-E-P-R.

So today I am going to be summarizing the presentations and discussions from the three staff workshops that were held on this topic as well as the written comments that we have received so far. All of the presentations from the staff workshops are on our website as well as the transcripts and the written comments if parties wish to look at those.

Given that I am summarizing three, full-day workshops in about an hour and a half I will be moving pretty quickly. So if I go too fast please just ask me to slow down. And I want to apologize in advance if I mis-characterize anybody's comments at the workshops or any of the discussions and ask that you clarify any errors that I may have made.

We do have the staff leads from the staff workshops here in the room. Mike Gravely on R&D Technologies, Judy Grau on Transmission, and we also have Pam Doughman on the phone, who conducted the July 21 workshop.

After the presentation we will take a short 15 minute break and then we will come back to a joint panel discussion -- pardon me -- a panel discussion of joint transmission projects with the municipal utilities and CAISO.

And then we will then have public comment starting with PG&E and a presentation by Ed Cazalet of Megawatt Storage Farms and then we'll hear public comment from the rest of the parties.

I will be summarizing the workshops out of chronological order because I want the transmission comments to be fresh in your mind when we go to the panel discussion.

The July 21 workshop covered how to estimate the 33 percent statewide retail sales for 2020.

What resource mixes have been used in various studies on this topic.

The impacts of contract delays or cancellations on meeting our RPS goals.

The range of potential price impacts.

Operational and physical changes that

will be needed to integrate renewables.

Potential impacts on natural gas demand, supply and price.

And finally, environmental concerns for developing large-scale renewables.

So first, what is 33 percent? The 20 percent by 2010 mandate was based on statewide retail sales and staff believed that that's the appropriate spaces for the 33 percent goal as well.

Based on the CEC's latest demand forecast, 33 percent of retail sales in 2020 is about 102,000 gigawatt hours. It is difficult to translate that into a capacity number because it is highly dependant on what the resource mix assumptions are.

The staff looked at four studies on the 33 percent renewable topic. First was the CEC Scenario Analysis Project, which was prepared for the 2007 IEPR.

Next was the CEC's July 2007 Intermittency Analysis Project Final Report.

Then we looked at a report that the Center for Resource Solutions did on achieving 33 percent renewables, which was prepared for the PUC in November of 2005.

And finally, work that is being done with the E3 GHG modeling work.

It is important to remember that each of these studies had a different focus and a different purpose. The CEC Scenario Analysis really focused on the greenhouse gas implications of using higher levels of preferred resources.

The E3 work also is focused on GHG implications and the costs of achieving reductions in the electricity sector.

The CRS report focused mainly on IOUs and on the incremental costs of moving from 20 percent renewable to 33 percent renewable.

And the Intermittency Analysis Project focused mainly on transmission system reliability and cost impacts.

So this slide compares the resource mixes that were used in the four reports, by technology. You can see a lot of wind, as we always see. Geothermal is the big baseload. And some solar and some biomass. I think at all the workshops we heard from parties that there's agreement that resource mix is going to be one of the key inputs into our analysis.

We then talked about contract status. The IEPR Committee asked the staff to look in the 2008 IEPR Update on the impacts of contract delays or cancellations. This shows the status of RPS contracts that have been signed since 2002.

In the 2007 IEPR the staff also compared POU renewable contracts with IOU contracts and found that at that time, as of July 2007, the POUs had about 550 megawatts of contracted renewables that were actually on-line and delivering. And that on August 2007 the IOUs had about 320 megawatts on-line. I think that number is closer to 400 megawatts today.

PRESIDING MEMBER BYRON: Ms. Korosec. Heads up to our utility members that are here. I really hope -- There's an awful lot of hatching on that last figure. I really hope the utilities will help address some of the questions that we will have about why there is so much hatching there. Okay, thank you.

MS. KOROSEC: This slide is from the PUC's quarterly report to the Legislature on RPS status. They are characterizing expected RPS generation by a level of risk. They have also identified risk factors for 2010 RPS generation, with the two primary risks being the production tax credit or investment tax credit availability and transmission constraints.

We also talked about cost impacts. This slide shows a comparison of the range of levelized cost estimates in 2008 dollars that were used in the various studies. Where you see a narrow range of costs, like with the biomass, that reflects the small number of studies that actually looked at that technology, rather than more certainty about the price. In looking at these costs the staff found that the input assumption with the highest impact on the levelized cost was capacity factor assumed for the technologies.

This slide shows the E3 supply curves on the 20 percent and 33 percent renewable. For 20 percent, biogas is the lowest cost. For the 33 percent goal we see that -- pardon me. Geothermal and wind are the lowest cost for the 20 percent. For the 33 percent, biogas is the lowest, followed by wind, solar and geothermal in that order with biomass being the costliest.

In terms of rate impacts. The E3 study found about a 13 percent increase in retail rates to reach 20 percent renewables and a 17 percent increase to reach 33 percent.

PRESIDING MEMBER BYRON: Suzanne, could you go back and slow down and walk us through what is on this supply curve. I am trying to jump ahead to where you are on it. What do the different curves represent here?

MS. KOROSEC: I would have to defer to Ms. Doughman on the phone. This is a slide from her presentation and I don't know the details about it. This was just generally to show which of the technologies are the lowest cost for meeting the renewable goals based on the E3 studies.

MS. DOUGHMAN: Hello. Would you like me to address the question?

PRESIDING MEMBER BYRON: Please go ahead. Identify yourself.

MS. DOUGHMAN: My name is Pam Doughman, I work in the renewable energy office.

This shows four curves, four supply curves prepared by E3. The green curves show the supply curves for 20 percent RPS. The curve on the bottom shows the net cost, which is total cost minus displaced energy and capacity. The top green curve shows the total cost, which includes bus bar, transmission and integration costs. And then the blue curves show the same thing but for 33 percent.

Does that answer your question?

ASSOCIATE MEMBER PFANNENSTIEL: Yes, thanks, Pam. Is this based on current costs of these technologies or is it some projected future cost?

MS. DOUGHMAN: I believe this is current costs.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks.

PRESIDING MEMBER BYRON: And it's great that you are on the phone to be able to answer these, Pam. I notice what is not on this curve, nor is it on Slide 10, is photovoltaic. Can you give us a sense of where that fits in in this analysis or was it not considered?

MS. DOUGHMAN: I will have to get back to you on that. I know the E3 greenhouse gas model has some PV and I think generally the cost is higher than the cost shown here. But I will get back to you on that.

PRESIDING MEMBER BYRON: Well that's okay. We also have PG&E here and they just entered into agreement with two large photovoltaic suppliers. I'm sure they can tell us where it fits in.

MS. KOROSEC: All right, thank you, Pam.

In terms of rate impacts, which is not shown on this slide, the E3 study found, as I said, a 13 percent increase in rates to reach 20 percent renewables and a 17 percent increase to reach 33 percent renewables. And these estimates are for changes in rates between 2008 and 2020 in real terms.

Now the CRS study concluded that in terms of retail price impacts, over the long run renewable energy actually has a beneficial net impact on ratepayer costs. The scenario analysis report showed about a ten increase in levelized costs as a result of the renewable scenario.

We then moved to a panel discussion which covered estimating the 33 percent requirement, comparing resource mix scenarios, impacts of contract delays and the range of potential costs.

Dr. Jaske from the CEC staff provided a summary of the Scenario Analysis Project, which he characterized as a what-if project, with the main emphasis on understanding the CO2 consequences of large volumes of preferred resources. This included energy efficiency, supply side renewables and rooftop solar.

The study was done on both a California and a WECC-wide basis and in terms of renewables focused on a high penetration rather than a specific 33 percent level. Although the high case scenario after making adjustments from net energy for load to retail sales corresponded to about 34 percent, which is in the right range of what we are looking at.

This was a physical study. It didn't examine contractual issues. It focused on planning level and how resources performed across seasons and months. So the results of the study don't really allow conclusions about impacts on individual load-serving entities and how they may choose to try to comply with a high RPS target.

The study looked at what resources would be displaced. It showed that as renewables were added generation from conventional resources went down. Generally the displaced resource was natural gas, both in-state and out of state, rather than coal. And in terms of cost, the high renewables case, as I said earlier, increased ratepayer costs about ten percent.

There were a lot of uncertainties that were uncovered in this project, some of which were evaluated explicitly like fuel process and hydro variation. Some uncertainties couldn't be addressed. A good example of that is technology cost change through time. And Dr. Jaske also noted that since the study was completed we have seen new construction cost numbers for renewables go up from ten to twenty percent.

Dr. Jaske also discussed resource adequacy requirements and how they might affect the ability to reach a 33 percent goal. Because of local reliability requirements to meet local load with local resources, adding large amounts of renewables to the system may be problematic since many of those resources are located outside of the local reliability areas.

There are ten load pockets in the state that are recognized by CAISO who does a study each year to determine the minimum amount of generation that is needed within each load pocket. It has to be secured by all LSEs with load in that pocket. Local needs are satisfied first and then system needs. For example, San Diego has an obligation to procure local resources, even if they would like to procure generation in Northern California because they have to satisfy their local obligations with local generators first.

The PUC puts constraints on the types of resources. They stress high availability. Because the purpose of resource adequacy is really to provide resources that can handle contingencies like forced outages of other generators or transmission lines. Another issue with resource adequacy is how to calculate the contribution from renewable resources to resource adequacy, given the variability of some of these resources.

Dr. Jaske noted that the PUC will be looking at this issue of renewables and resource adequacy in their resource adequacy proceeding. If they down-rate wind compared to the methods that have been used in the first two years of resource adequacy that is likely to reduce capacity payments to wind projects.

Dr. Jan Hamrin then summarized the report that Center for Resource Solutions did. It was focused on the IOUs and on the incremental impacts of moving from 20 percent to 33 percent. In coming up with a 33 percent target they used the load of the utilities at that time and escalated it by two percent per year. They assumed a resource mix of 50 percent wind, 30 percent geothermal, 10 percent biomass and 10 percent concentrated solar.

Related to your question, Commissioner Byron, if their study did not include photovoltaics. Not because they didn't feel it was important but because at the time the policies were that PV did not count towards the RPS.

The CRS report did conclude that it is economically feasible to reach 33 percent and that doing so would result in a net savings to California consumers over 20 years. They saw a small, negative ratepayer impact between 2011 and 2020 of less than one percent. But that was offset by longer term benefits between 2011 and 2030 of as much as 175 million.

Dr. Hamrin said that renewable costs have increased more than the CRS report anticipated. They are about 36 percent higher today than what they were in the study. But she also noted the capital costs of natural gas plants have increased by about 100 percent based on information that she had from DOE.

We then discussed the Intermittency Analysis Report briefly. Dr. Dora Yen-Nakafuji from Lawrence Berkeley National Lab talked a little bit about this. How it evaluated how the transmission system will need to look at how to accommodate dispatch of high levels of renewables. How these resources can benefit the grid. It also looked at where adding renewables would cause problems on the grid.

It focused on California and looked at some economic metrics but was primarily a transmission and operational study focusing on high penetration of wind. She did not go into detailed assumptions that were used in the study because they were rather lengthy. And that study is available on our website if people want to look at that in more detail.

Dr. Snuller Price then gave a brief overview of the E3 modeling tool that she characterizes as being created to run many different scenarios and to allow stakeholders and parties in the CPUC process to run their own view of the world.

In estimating 33 percent of retail sales Dr. Price felt that the big drivers are energy efficiency assumptions, PV, combined heat and power and behind the meter generation as well as potential electrification of the transportation sector.

Regarding resource mixes he noted that any mix we select is simply one reference case and that there is no right mix.

In terms of cost, the E3 model tried to estimate by LSE, both for POUs and IOUs, what the cost impacts of moving to 33 percent would be. They concluded that retail prices are likely to increase regardless of what scenario that we use. But that in a 33 percent scenario they actually go up more. He said that the model showed about a five percent increase in retail prices of moving from a 20 percent renewable level to a 33 percent level.

ASSOCIATE MEMBER PFANNENSTIEL: Suzanne, earlier you gave from their supply curve about a four percent difference.

MS. KOROSEC: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: So this is about the same amount.

MS. KOROSEC: Yes, I think it's like a rounding kind of thing.

ASSOCIATE MEMBER PFANNENSTIEL: Okay, thank you.

MS. KOROSEC: He believes that the current procurement process will produce 33 percent by 2020 in terms of contracts but was less optimistic about actual generation.

He also underscored the need to look at processes for starting new transmission facilities, noting that with the time it takes to put in transmission lines 2020 really isn't all that far away.

The panelists then made some comments about the questions. Dr. Hamrin said very month of delay in building a renewable project costs about one-and-a-half percent of the value of the power purchase agreement, which she characterized as a pretty high-risk premium.

She says that she sees the current RPS process as a major barrier to meeting the 33 percent goal and has heard anecdotally that there are projects bidding into RPS solicitations that have permits and transmission that are not getting selected. And she felt that a feed-in tariff might be one solution that would allow us to get more renewables.

She also suggested the PUC may want to clarify the impact of not complying with the RPS and what fines would be imposed and under what circumstances. And also suggested a milestone procedure for RPS contracts may be helpful. Some type of financial penalties for not meeting those milestones to encourage projects to come on-line.

PRESIDING MEMBER BYRON: I'm wondering how Dr. Hamrin heard about bidders into these various RFOs for renewables since I read yesterday, which surprised me, they have to sign confidentiality. They cannot even disclose that they have submitted bids. So somebody is talking. Sorry, go ahead.

MS. KOROSEC: Dr. Hamrin also noted that 20 percent of the national voluntary market for RECs is being sourced from California and that the voluntary market has resulted in as much or more renewable energy coming on-line than the RPS has. It doesn't mean that the potential for the RPS isn't much larger but it does show that the voluntary market is actually delivering.

Dr. Yen-Nakafuji says we need to take a portfolio approach to renewable resource mixes and work within our existing framework considering market constraints, the regulatory environment and current technologies. She believed that transmission and siting are what are hindering renewable development as well as lack of developer incentives to come to California. Other states are providing statewide incentives for developers to locate there. So we have lots of competition for resources from other states.

Dave Hawkins from CAISO then presented their view. He stressed we need to have a regional not just a statewide view. He feels that imports are a critical piece of the puzzle and that we will meet our 33 percent goal only by using out-of-state renewables.

He also felt we need to be considering the impacts of climate change on the availability of resources such as changes in snowpack and snow melt that will affect hydro availability and timing.

He also felt that PV is going to be a very important resource and he characterized as much as five to eight percent of our potential generation is behind the meter.

He also felt we need to expand our demand response programs to increase the amount of overall electricity demand.

He believes that one of the major impediments to reaching the 33 percent goal as we all know is siting and permitting, not procurement. He doesn't believe a feed-in tariff is necessary to encourage new development. He cited activity in Texas and how they are very friendly to developers and helpful in siting new facilities as being maybe a better model.

CAISO does believe they can make 20 percent work. For 33 percent there are some areas that need further examination. This was better wind and solar forecasting capability and connecting forecasters to floor operators. How much ramping regulation that we need, what kinds of energy storage technologies will be available.

How do we change the market structure and tariffs so that we can use short-term storage to give us regulation flexibility. And can the gas storage system accommodate rapid swings in conventional generation that would be needed to back up renewables. And how do we communicate the need for additional gas storage to operators as we are going through that.

Jaclyn Marks from the PUC then talked

about their proposed staff analysis on 33 percent renewables. This will form the IOUs' long-term procurement plans. They are holding a workshop on August 26 to seek input on the structure and data requests for that study, which will be used to direct the IOUs on what the PUC views as realistic RPS scenarios.

Phase 1 of the study will be a cost and resource build-out scenario by early February of 2009 with key inputs including data from the RETI, the Renewable Energy Transmission Initiative process, load resource tables that are coming out of the E3 work and integration cost data. They will also try to identify who the key players and agencies are in making 33 percent a reality and what the state can do to overcome barriers.

Phase 2 of the study will look at policy uncertainties beyond 2020 like emerging technologies, electrification, smart grid and the impact of rooftop PV.

The PUC agrees with CAISO that procurement is not the reason we are not meeting RPS goals. They have approved 5900 megawatts of contracts with about 400 megawatts on-line.

And their independent evaluators have

concluded that procurement here is working and that it is not more complicated than any other procurement process for renewables in other states. And that in fact it is more streamlined and predictable than the procurement for fossil resources because the annual process is the same. But they believe the problem is permitting and siting of generation and transmission facilities.

PRESIDING MEMBER BYRON: You're so fast.

MS. KOROSEC: I'm sorry.

PRESIDING MEMBER BYRON: Was that the PUC that made those conclusions?

MS. KOROSEC: Yes, these were comments made by Jaclyn Marks.

PRESIDING MEMBER BYRON: Thank you.

MS. KOROSEC: And I'll try to slow down.

We then had a panel discussion on physical and operational changes needed in the system; potential impacts on natural gas demand, supply and price; and environmental concerns with siting large renewable power plants.

CAISO believes more can be done to link renewables with demand side thermal storage technologies. For example, they would like to see compressor loads for chillers in large buildings have a variable capability. And it would be good to see the state take a leadership role on this in retrofitting our own buildings to allow the CAISO to send a signal saying that the wind is ramping up or down so that building output could be changed in response.

Dr. Yen-Nakafuji said it is important to connect those that do long-term transmission planning with the operational side that actually does the dispatch of resources. She also noted we need to better address the seasonality of resources and have better forecasting for solar.

Dr. Price felt reliability is very important when we think about 33 percent renewables. Looking at the quantity of renewable generation we need to add to meet 33 renewables, there's not enough room for conventional generation. So it is not simply a matter of adding renewables to meet load growth. He estimated we will be displacing something like 11 percent of conventional resources by 2020 and that this is going to require a very different planning perspective.

Ms. Marks from the PUC agreed that we need new ways of planning to avoid being stuck with stranded costs in the future. She felt encouraged that the CAISO was studying the operational impacts of 20 and 33 percent renewables and would like to see some quantification of the ramping and regulation that will be needed to integrate renewables, particularly since that is likely to come from peaker plants.

We then talked about natural gas issues. Pam Doughman, who is on the phone, provided an overview of some work that has been done by Ryan Wiser and Mark Bollinger of Lawrence Berkeley National Lab on the potential effects of high levels of renewables on natural gas prices.

They reviewed 13 studies of potential federal RPS programs ranging from 7.5 to 20 percent renewables. They concluded that most of the studies showed a net impact of $7 to $20 per megawatt hour savings on electricity natural gas bills across the US. They also estimated changes in natural gas demand if investor-owned utilities meet the 33 percent goal. And found that demand for natural gas could drop about one percent per year from 2011 to 2020, reaching about nine percent below 2010 levels.

They estimate gas demand would increase slowly between 2020 and 2030, reaching about eight percent below 2010 levels. And that this reduction in demand could result in natural gas savings from 2011 through 2030 with the estimated net present value of these savings in 2011 dollars between $800 million and $2 billion.

ASSOCIATE MEMBER PFANNENSTIEL: Suzanne, were those savings captured in the E3 price forecast model?

MS. KOROSEC: I don't know the answer to that. Pam?

MS. DOUGHMAN: I don't think so.

ASSOCIATE MEMBER PFANNENSTIEL: All right, maybe we should check on that.

MS. KOROSEC: Okay.

PRESIDING MEMBER BYRON: And just to backtrack for a moment. This is the PUC's analysis again or have you moved on?

MS. KOROSEC: No, this is from Ryan Wiser and Mark Bollinger of Lawrence Berkeley National Lab.

PRESIDING MEMBER BYRON: Okay.

MS. DOUGHMAN: Can I jump in? They did this analysis as part of the study that was completed for the CPUC that was led by CRS.

PRESIDING MEMBER BYRON: And did they look at capacity in addition to looking at consumption? For instance, if we were to be very favorable with a capacity factor of renewables in general of, let's say, 30, 33 percent. Pick an easy number. Did they look at how much capacity would have to be built in order to meet these kinds of projections? Not just for renewables but also for firming up the renewables and for -- I'm always reminded, the other 67 percent of the generation that is not included in the 33 percent.

MS. DOUGHMAN: I am not sure how they went from the energy increase of renewables from 2010 to 2020, how they went from that number to the estimate of the decreased demand for natural gas. So I'll need to talk to them and get that to you later.

PRESIDING MEMBER BYRON: Okay. And recognizing what we are doing here. We are summarizing material that was covered in the workshop previously.

MS. KOROSEC: Right.

PRESIDING MEMBER BYRON: And so a lot of this is available and we, as commissioners we need to do our homework and go get it.

MS. KOROSEC: But I'm glad you are identifying the question because we need to know what it is we need to get back to you with.

PRESIDING MEMBER BYRON: Okay, thank you.

MS. KOROSEC: As Pam said, the CRS report included some of this analysis and it estimated that the natural gas suppression effect based on this analysis concluded that the incremental value of moving from 20 to 33 percent to displace natural gas is about 3.5 dollars to 8.5 dollars per megawatt hours, depending on the inverse elasticity that is used.

In the scenario project Dr. Jaske noted that they looked at the gas impacts of increased levels of renewables in the scenario of both California and the rest of WECC. This scenario had the largest likely reduction in power plant natural gas usage and therefore the largest potential price reduction.

The results indicated a big reduction in gas use for electricity generation and price reductions in the range of 50 cents to $1 per million BTU. However, this methodology didn't include any physical or long-term response from natural gas producers. And we would have to assume that if they knew that the demand was going to be less over time they would not be making a lot of long-term investments.

So the staff ran the GPCM model to incorporate those behavioral changes and came up with costs more in the range of 10 cents to 25 cents per million BTU reduction. There was a second analysis prepared by Altos for staff and it came up with a small impact as well.

Given that these were unproven assessment methodologies the 2007 IEPR noted that this effect is there of reducing natural gas but said it couldn't be quantified and therefore we can't really rely on that.

Dr. Price from E3 said he is hesitant to count on natural gas price reductions from increased use of renewables because natural gas is a regional market. And we may see increased demand for gas in other states because of limitations on new coal development and that may drive the price up.

After the panel discussion SMUD commented that we need to consider the impacts of strategies to reduce load, like passive solar heating and cooling. Also made a side note that when considering the cost-effectiveness of renewables we need to consider national security issues.

The League of Women Voters said that they would like to hear more about the potential for combined heat and power and also see some realistic projections of that potential.

They also asked for clarification on when we talk about DG is it solar PV or is it CHP or are there other forms of DG included. And how they fit into the overall portfolio of generation and resource procurement.

The League of Women Voters also said it is important for us to have energy elements in local communities' general plans. And that those communities need to get involved in the renewable procurement planning process. She was curious whether these communities could meet their long-term needs without transmission simply by using distributed generation technologies.

For written comments. I'm taking a little longer than I had expected to do. I don't know if you would care for me to --

PRESIDING MEMBER BYRON: That's perfectly okay.

MS. KOROSEC: All right.

PRESIDING MEMBER BYRON: Take your time.

MS. KOROSEC: All right. I'm seeing eyes glazing over and people shifting in seats.

PRESIDING MEMBER BYRON: Not at all.

MS. KOROSEC: I didn't want to test your tolerance here.

On estimating 33 percent renewables. The California Municipal Utilities Association noted that given the transmission additions that are going to be driven in part by megawatts added we need to have some agreement on the actual amount of renewable capacity that is needed. CAISO has identified roughly 9600 megawatts to meet the 33 percent goal while the Consortium for Electric Reliability Technology Solutions, or CERTS study, identified a range of 23,000 to 40,000 megawatts.

PRESIDING MEMBER BYRON: I saw that. That's an enormous difference.

MS. KOROSEC: Yes, it's a huge difference. A lot of that depends on resource mix assumptions and capacity factors but we need to get that nailed down, I think.

On the issue of 33 percent as a mandate. SDG&E said that we need to understand the issues and obstacles associated with higher levels before making this a mandate.

In contrast the Green Power Institute said that a long-term stretch goal for renewables is needed to ensure the flow of investment capital in the state.

Renewable resource mixes. Edison identified a number of assumptions that will need to be made. I think most of those have been identified in the materials that have gone out about this. Load, energy efficiency, fuel prices, effects of carbon legislation, things like that.

The Alliance for Responsible Energy Policy said that the cities of San Francisco and San Jose have begun to implement or are considering adopting policies and programs based on European principles that would allow us to meet our RPS goals within ten years without building one new utility-scale project or one new transmission line. So that's something you may need to look at.

On contract delays or cancellations.

Edison said that responses to recent RPS solicitations are robust and they are increasing and they expect that participation to continue to expand. They believe delivery is still the limiting factor. So state agencies with responsibility for transmission, siting, permitting and tax credits need to work together to reduce delays.

Because projects can be delayed by permitting and licensing and construction of new transmission Edison suggests we build a scenario which says that achieving a 33 percent 2020 goal is unrealistic. They also noted that procurement of renewables by electric service providers is lagging.

PG&E stated as of mid-year 2008 it has renewable resources on-line or contracts signed for over 21 percent of its projected load for 2010.

SDG&E agrees that procurement is not the barrier to renewable development and recommends that the CEC focus our IEPR efforts on determining what the state can do to facilitate the timely development of projects already under contract.

Green Power Institute said that if

retail providers continue to gear procurement towards just meeting the goal they are not going to make the mandate. Because not all signed contracts will result in operating facilities.

They also echoed Ms. Hamrin's comment stating they are aware on an anecdotal basis of viable projects that wouldn't require major transmission upgrades that have been overlooked in the process.

And they have warned against using transmission access as an excuse for failure to meet the current targets or as an argument against setting a 33 percent by 2020 target.

On feed-in tariffs. PG&E feels the current solicitation method is working and that's the appropriate method, not feed-in tariffs, for higher penetrations of renewables. They do offer a standard contract currently for generation up to 1.5 megawatts of the market price referent. And they have executed contracts with generators between 1.5 megawatts and 20 megawatts through competitive solicitations and feel this is the appropriate process.

SDG&E thinks that feed-in tariffs can be used as a solution for niche projects such as those that are too small to participate in RPS solicitations.

GPI, which is Green Power Institute, said some project proposals to utilities may be too good to resist but they are not viable in the real world. And that standard contracts with preset feed-in tariffs could improve the success rate for new projects.

The Alliance for Responsible Energy Policy discussed the success in European countries from the use of feed-in tariffs and said that Michigan, Illinois and Rhode Island are also proposing feed-in tariffs for small wind projects now.

On potential price impacts GPI notes there's little doubt that overall energy costs will increase in the future with the phasing out of fossil fuels. But that it may not matter because meeting a 33 goal is of over-arching importance.

Edison says that the 2007 IEPR Scenario Analysis Project was a good start in looking at price impacts but that actual data is very different from the assumptions that were used in the analysis. They believe that wholesale costs to purchasers are going to increase quite a bit by implementing a 33 percent goal.

SDG&E recommended several measures to ensure that a 33 percent mandate is fair, achievable and affordable. It should apply to all LSEs, including the publicly-owned utilities. Costs should not be subject to the AB 1X cost cap. RECs should be permitted from both within and outside the state. The PUC should implement a ratepayer cost protection mechanism to ensure renewable procurement is affordable. And existing, flexible compliance provisions and the excuse for lack of transmission should be maintained.

Regarding the operational and physical changes Edison believes we need to look at changes needed in gas operations, echoing what the CAISO folks said, to account for variable usage of the gas system to balance load and generation. They also say operational issues associated with higher levels of wind production will increase costs and that CAISO needs to analyze these factors and their potential impact on customer interruptions. They also noted the need for additional studies on the type and timing of storage technologies to meed grid operation needs.

On the issue of demand side strategies Edison thinks these programs really weren't designed to reduce impacts of renewable generation and that the issue is going to require more study.

PG&E believes the state will need to address the concerns about upgrades in the transmission infrastructure, the effects of once-through cooling regulations on resource adequacy, and the adequacy of storage technologies in a holistic manner as opposed to an incremental approach.

GPI believes that uncertainty associated with intermittent generators is simply another source of grid uncertainty similar to load that has to be managed when maintaining grid integrity. They also felt weather forecasting was a keen means to managing the uncertainty of intermittent generators.

On the potential impacts of natural gas demand and price. Edison believes with 33 percent renewables there is going to be some decrease in fossil generation. But because the system may need to use higher heat rate units to control operations and have more start-up fossil generation, that would require more natural gas usage. They also believe it is difficult to forecast decreased natural gas demand because that is going to depend on the renewable portfolio mix and on other assumptions.

PRESIDING MEMBER BYRON: Perhaps they forgot to factor in the retirement of aging power plants and once-through cooling coastal plants.

MS. KOROSEC: On environmental issues the California Hydropower Reform Coalition opposes weakening the definition of small hydro in the current statutes because of the environmental impacts.

SCE simply notes that a 33 percent scenario will require large plots of land for wind and solar installations.

And the Alliance for Responsible Energy Policy believes that California has rushed in to identify CREZs, these competitive renewable energy zones, and permit new transmission lines, and that's failed to adequately consider DG and demand side management alternatives.

So the main take-aways from this workshop were, I think, the 33 percent goal should be based on statewide retail sales and assumptions of needed capacity or energy need to be consistent between all of the analyses.

The main, physical barriers that seem to need to be addressed are transmission and operational constraints. We will need to consider findings from the CAISO's operational studies and future analyses as well as data and findings from RETI and the PUC study on 33 percent renewables.

There's also potential policy issues that are going to need to be better understood like local reliability requirements and once-through cooling policies. As well as issues that are associated with backing out large amounts of conventional generation as we add renewables.

And we also need to look at how DG can reduce load and reduce the need for new transmission in key locations and potential contribution to renewable goals from behind the meter generation. We need to consider recent increases in renewable costs as well as increased costs of building natural gas facilities. Retail rates are likely to increase but they could be offset by longer term benefits to ratepayers so we need to look at that. And we need to better understand the displacement effect on natural gas of renewables.

So a deep breath and we move to the next workshop.

The July 31 workshop focused on emerging technologies that can help to integrate renewables. There were a number of presentations on various emerging technologies. I'll try not to go into a lot of detail about each presentation because they were highly technical. They are available on our website. But I will give a brief overview of each presentation.

The staff presentations focused on technologies that can provide support in terms of integrating renewables such as phasor technologies that measure system performance and then feed data back into the IOUs with the goal of increasing grid stability.

Demand response technologies. Demand response can be used as a spinning reserve for renewable firming and support and it can help avoid the need for new power plants.

Fault current controllers that can stabilize the grid by allowing it to operate at a higher capacity so that we can be adding renewables without needing new lines.

And then energy storage technologies, which are pumped hydro, compressed air, energy storage, flywheels and batteries, thermal storage and hydrogen storage. Fuel cells that are reversible, super capacitors and super-conducting magnetics.

The staff presentation also discussed how renewable technologies could be used for renewable energy-secure communities and buildings. They believe there is a need to expand our consideration of renewable technologies beyond electricity generation technologies to things like solar heating and ground source heat pumps. Because that can reduce electrical loads needed to meet thermal needs.

The staff noted that the PIER program has three collaboratives for renewable technologies, biomass, geothermal and wind. They are currently developing a fourth for solar.

They are planning three renewable R&D solicitations this year. The first is for utility scale renewables, the second for renewable-secure communities, and the third for renewable-secure buildings. The targets of the solicitations include things like thermal storage, solar and wind forecasting, strategies to exploit local renewable resources and transfer of emerging and commercial renewable heating and cooling technologies to the California market.

We then had a presentation from the PUC. They briefly discussed their Emerging Renewable Resource Program or ERRP. This is a two-year pilot program that is intended to focus on technologies that have completed development but are not yet commercialized.

They feel this program fills an important gap in the RPS program because current evaluation protocols don't work when we are looking at pre-commercial technologies. And they feel that power purchase agreements for unproven technologies aren't as secure as those with proven technologies.

They are also seeing emerging technology projects bidding into current solicitations at levels far above the market price referent. And they would rather see these developed as demonstration projects rather than allocating scarce, above-market funds to those technologies.

We had a presentation by AWS Truewind on wind forecasting. The key points from this were that state-of-the-art forecasts are produced with a combination of physics-based and statistical models.

The quality of data from a wind park is a significant factor in how well the forecast performs. Centralized systems have been implemented at several balancing authorities in the US and others are in the process of designing or implementing these kinds of systems.

And grid integration studies suggest that day-ahead forecasts have a potential value on the order of hundreds of millions of dollars to stakeholders and the grid system.

We then had a presentation by Solar Millennium LLC on integrating thermal storage with concentrating solar power.

The major points are storage can improve the economics of solar thermal power plants. It can increase availability and plant capacity factors. It spreads generation over more hours. It allows you to focus generation in peak hours. It also allows plants to ride through a cloud transient, which apparently is a big problem in places like Arizona. And they feel that molten salt technology is proven and risks are manageable and there is a clear market pull from many of the utilities.

We then heard from EPRI on energy storage. It can be used for load leveling, ramping, frequency regulation, and to manage renewables in time. Storage technologies provide smoothing as energy ramps up and load shifts during the ramp. It can also smooth out frequency variation as well as fluctuations in renewable generation.

These fall into three economic categories. For peak we have batteries, flywheels, super capacitors and super conducting magnetics. In the intermediate category, compressed air energy storage, flow-type batteries. And for baseload we have compressed air and pumped hydro and some batteries.

A key point of this presentation was that to quantify the benefits of storage you really need to look at the aggregate benefits to determine the cost benefit ratio.

We then heard from CIEE on emerging transmission technologies. They pointed out the transmission system grid wasn't really designed for intermittents and the system needs to change to accommodate the unique behavior of these technologies.

Transmission needs to achieve three broad objectives. We need to provide physical access for each new power plant with faster siting and approval of transmission lines. Transmission also needs to reliably accommodate unique renewable generator behaviors. And we need too increase the system's power carrying capability to handle the additional electric flows by decreasing thermal constraints, decreasing stability constraints and planning for system expansion.

The presentation concluded that to meet the 33 percent goal we can't simply rely on build solutions like wires and towers and power plants. But instead we need new transmission technologies that may renewable integration easier and less costly. And ultimately that we will need smart grid to be able to integrate the maximum amount of renewables.

The next presentation was by Dariush Shirohammadi from Oak Creek Energy Systems. He said concerns about integrating renewables are overblown. And he contended that much of the transmission operators' experience with renewables was with early machines that really didn't operate very well and new renewables can perform as well as any conventional generator and sometimes better. He feels we don't need any more regulation than we would need with conventional generation other than upward ramping.

He said we need to completely rethink our planning and operating practices because we tend to over-build transmission.

He also recommended focusing on ramping and load following rather than on frequency regulation.

He believes we should have diverse renewables that complement each other rather than combustion turbines to provide backup.

He feels energy storage is the best solution but the technologies are still in development phase.

EPRI then talked a little bit about distributed generation. Provided some examples of where fossil fuel DG can be integrated with storage systems, like natural gas generators and CHP applications or micro-CHP for homes.

They are also developing a unit with one-half megawatt of power and two megawatt hours of energy that can help integrate wind and be installed near substations. They have had some utility interest on those systems.

I noted that the benefits of solar energy can be enhanced by adding DG storage to the system.

We then heard from Sun Edison who focused on community scale PV. They expect to see grid parity for the cost of these PV systems around 2012, based on numbers that they are seeing from NREL.

Sun Edison recommends establishing community solar parks on open areas or brownfield sites like landfills and military bases. Where utilities purchase power directly from the solar park at a fixed rate through a special purpose tariff or bilateral agreement. The utilities could then pass the benefits on to participating customers through a solar tariff.

There are some barriers to this. The lack of community choice aggregation and the inability to do direct access transactions.

California Wind Energy Collaborative is the last presentation of the day. A big sigh of relief from all of you.

As of 2006 there are approximately 2500 grid-connected, small wind turbines in use in the US. These are typically one to ten kilowatts but can range from 300 watts up to 100 kilowatts.

Sales in 2006 were about $56 million, outside the US about $61 million. But about 98 percent of all the turbines sold were manufactured here in the United States. They can be used in residential, business, industrial and agricultural applications.

System costs have been fairly steady at $5 a watt or 15 to 18 cents per kilowatt hour. This doesn't include net metering and other incentives that can improve the economics.

And the Wind Energy Collaborative believes that using these small systems at the community and distribution levels in California would provide benefits in the form of reduced electricity needs and costs as well as reduced emissions.

Barriers include local ordinances and permitting requirements, permitting fees and equipment certification.

So the important conclusions from this workshop I think were that there are a number of emerging technologies out there that can help reduce the impacts of integrating renewables into the system by increasing the carrying capacity of existing transmission lines, improving transmission capabilities with new technologies and providing energy storage to address ramping and regulation concerns.

But we need to really better understand where these technologies are in terms of development, commercialization and cost to know how much they can contribute to the 33 percent goal. We also need better forecasting and variable technologies like wind and solar and better connection between forecasters and system operators. And the smart grid concept may be an essential strategy in maximizing the amount of renewables that we can integrate into the system.

PRESIDING MEMBER BYRON: I'll just give you a break for a second, Ms. Korosec. I'm really sorry that I missed this workshop. You know, having been kicking around this industry for a long and the fact that transmission is essentially the same technology for the last 80 years with little changes, incremental changes. But we forget sometimes that there are opportunities for great technology breakthroughs and I am really sorry I missed this workshop.

I don't think you mentioned the conductors. You know, the fact that there was one presenter as well that was looking at conductors that could carry three times the existing capacity. I was very intrigued by that.

MS. KOROSEC: Yes, yes.

PRESIDING MEMBER BYRON: But increased capacity, operational control, efficiency, firming, improved forecasting. All these things have a lot of room for improvement and it is not just building more wires that can help solve this.

So I am also very pleased that this Commission is very much involved in these activities through our PIER program and our transmission -- forgive me, Ms. Ten Hope.

MS. TEN HOPE: Research, TRP.

PRESIDING MEMBER BYRON: TRP. The Transmission and Research Program.

MS. KOROSEC: Yes.

PRESIDING MEMBER BYRON: I get the TLAs messed up, the three letter acronyms. So break is over. Go back at it.

MS. KOROSEC: All right, all right.

Going to the July 31 workshop. So it was the third and last workshop. Pardon me, the July 23 workshop.

The staff made a presentation that identified major recommendations from our 2007 Strategic Transmission Investment Plan. These included that stakeholders should develop a road map for renewables.

The CEC should participate in RETI and integrate the results into the next IEPR and Strategic Plan.

We need to leverage our power plant licensing and transmission corridor designation authority with our environmental expertise and transmission planning policy experience.

We should work with the PUC and the CAISO to resolve issues associated with the CAISO interconnection queue.

The PUC should continue to coordinate its generation procurement and transmission CPCN processes.

And the CEC staff should continue directing research by CERTS, the Consortium for Electric Reliability Technology Solutions, aimed at removing barriers.

These are some of the current transmission initiatives that were identified in the workshop. I won't go through these in detail.

Staff also identified supporting initiatives that address transmission barriers.

We then moved to a presentation by CERTS on their study. As I said earlier, they believe that California needs to integrate 23,000 to 40,000 megawatts of new renewables in the next 20-plus years. So they focused their study on a mid-range of 30,000 megawatts of additions.

They said that major load centers are served through transmission gateways that surround load centers. Integrating renewables requires connecting to the backbone grid, updating the backbone grid to the transmission gateways, and expanding transmission gateways for deliveries to load centers.

The study focused on the LA Basin as a transmission gateway expansion. Pardon me, the LA Basin transmission gateway expansion as the funnel point for about 20,000 of the 30,000 megawatts of renewables.

They concluded that we need to triple the current transmission gateway capability to accommodate renewable capacity additions.

That shutdown of local generation will increase the need to expand this gateway capacity.

That we need transmission links between LA Basin to Northern California and San Diego.

Local network reinforcements are needed like upgrading lines or installing fault current limiters and breakers in remedial action schemes.

And we need additional regulation and ramping which can be addressed by storage, demand management and automatic load control.

Their recommendations included the need to move the planning horizon out 15 to 20 years to define long-term requirements. CAISO also needs to give utilities and the PUC guidance on the resource attributes that are needed for better operability of the grid. And policy makers need to support early planning for transmission gateway capacity and deliverabilty of load centers well in advance of renewable development.

CAISO then presented a summary of their preliminary transmission plans for meeting the 33 percent goals. These plans are intended to support RETI by speeding up the transition from designating competitive renewable energy zones, or

CREZs, to conceptual transmission identification.

They provided an estimate of the amount of transmission capacity additions that are needed to meet the 33 percent goal and potential compliance results that are depending on the resource mix.

The study identified the six lines. These are the first three, these the last. These are beyond the Tehachapi Renewable Transmission Project and the Sunrise Power Link, that will enable the goal to be met.

We then held a couple of panel discussions to answer the following questions. What is the role of the panelists in relation to the various transmission initiatives and to accomplish the 33 percent goal? Will existing initiatives be enough to remove the major transmission barriers? And if not, what's missing? And are these initiatives complementary or incompatible? And if they are, then why?

So we first heard from utilities and agencies. LADWP says they have an internal goal of 35 percent by 2020.

IID says that their gateway is Devers-Mirage. They agreed with the Path 42 upgrade that was mentioned in the CAISO presentation.

CMUA said that munis were initially concerned about RETI slowing things down but they are generally pleased with the analytical work to date and RETI's ability to bring together diverse stakeholders. They believe transmission planning should be spearheaded under a western umbrella and that the WECC's transmission expansion planning policy committee is well suited for this. They felt the initiatives are compatible but they need to be streamlined and consolidated.

PG&E believes the initiatives to be mostly complementary but that we need to look out 15 to 20 years, as the CERTS analysis did.

Southern California Edison believes that projects such as the Antelope and Tehachapi Renewable Transmission Project improve the gateway from SCE to the LA Basin. They need to identify corridors, especially one from north of Lugo to the LA Basin. And they felt that the processes to get renewable transmission are in place, but the question is, will they work.

CAISO said that when FERC dictated the large generator interconnection procedures back in 2002 nobody foresaw the explosion of renewables that we are seeing. Currently 70,000 megawatts in the queue. The CREZs that result from RETI will inform both the unified planning assumptions as well as the study planning components of their transmission planning process.

The PUC said that they are optimistic that RETI and the CAISO queue reform will help get the job done. They believe that joint muni and IOU projects are important. Something we will be talking about a little bit later. They also said initiatives are complementary with RETI being all-inclusive, but they are concerned that federal agencies are under-funded and understaffed to expedite transmission crossing BLM lands.

BLM says they have a proactive goal to house renewables. They currently have 75 solar and 94 wind applications totaling 1.3 million acres.

Next we heard from stakeholders on the same questions. NRDC advocates protection of public land. They feel we need smart transmission that takes account environmental costs and concerns. They believe RETI will steer us away from sensitive areas to areas that appear more suitable.

Oak Creek Energy Systems said we need a fundamental reform of existing initiatives. Many existing processes produce marginal results. Though the CAISO's generator interconnection queue reform is an example of a fundamental reform that seems to be working. And that RETI is a good step forward.

Bright Source Energy was pleased with the generator interconnection queue reform as well as with RETI. They are also happy with the ability to address issues early such as farm issues. They feel we need a transmission planning process that looks forward and not one that is designed to solve yesterday's problems. They also suggest we take a transmission optimization approach rather than a cost-effectiveness approach.

The Geothermal Energy Association says all three resource types, geothermal, wind and solar, need to figure out how to support each other. They say lots of private land is available so we need to get the locals more involved.

The League of Women Voters says the transmission system is the backbone. It's changing rapidly. We need to factor in distributed generation and smart grid. They are supportive of energy elements and general plans and they are willing to work with local governments on their energy elements.

The US Air Force raised concerns about land and transmission that is near designated zones. Concerns both for them and their sister military branches. And that's why they believe that the RETI, the WREZ, Western Renewable Energy Zone, and CEC activities are important. They believe RETI may need top be brought in to include sub-regional groups such as those representing the Western Mojave Region.

DRA said we need collaboration and coordination among the initiatives as they progress. They believe the PUC's transmission OII helps with coordination. They view RETI as informing the PUC on transmission planning processes -- pardon me, transmission CPCN cases, with the caveat that we don't use the 33 percent deadline to circumvent transmission planning and environmental analysis in those.

They support public outreach even before transmission CPCN filings are made. And they would appreciate transmission developers filing more complete CPCN applications that address reliability and economics so that they don't have to do it.

Finally, the California Association of Counties. They don't believe the existing initiatives are sufficient. They believe that legislative and regulatory reform are needed out of the RETI process. They are cautiously pessimistic that RETI can do more than create a report that will then be ignored.

PRESIDING MEMBER BYRON: That was cautiously pessimistic?

MS. KOROSEC: It is cautiously pessimistic, yes. And they noted that Imperial is one of the few counties that has both an energy element as well as a transmission element in its general plan. They called Imperial County the Persian Gulf of renewable resources but with more conflict.

(Laughter)

MS. KOROSEC: We then moved to a moderated session to talk about links between initiatives. Just very briefly. I believe it is important to educate people about climate change. What it will take to address it. People need to understand the importance of getting transmission in and getting renewables on to the system. We need to bring cities into the education effort.

When you file for a CPCN there's always somebody who is not happy who will say they are not included. So we need to have designated corridors that provide a warning that someday this will be a transmission line here. They also believe that we shouldn't redo RETI's alternatives analysis when a CPCN is filed.

Some parties felt that all the public education about global warming goes out the window when a 500 kV line affects somebody directly. And that we may need to over-select some corridors just in advance just to have them.

RETI appears to be the front runner among the initiatives. And we need to be giving deference to CAISO analyses and long-term procurement proceeding results in our CPCN proceedings.

We need to link up transmission policy with energy efficiency and DSM.

And if you do joint transmission projects they have to be vetted as least-cost, best-fit among ratepayers.

BLM had three simple words, communicate, communicate, communicate. And I think that was echoed by a lot of the other parties.

So finally the written comments for this. And I will try to be brief except for the joint comments by the munis that will feed into our panel that we are doing after a break. A well-earned and well-deserved break for all of you.

The Alliance for Responsible Energy Policy said they believe we haven't adequately covered DG and DSM alternatives and that RETI will create a dangerous precedent that will lead to habitat destruction, displacement of homes and businesses and property devaluation.

Imperial Irrigation District supports initiating a joint transmission project with SCE on Path 42. They believe transmission projects that cross multiple balancing authorities must be integrated to ensure lowest cost to all California consumers. They believe transmission policies across California and neighboring balancing authorities must be addressed where there are barriers.

PG&E said a critical factor to ensuring

that the initiatives are successful is to match the resulting transmission plans are requirements of commercial realities. Without true integrated planning PG&E is concerned that building new transmission lines may miss the commercial reality and viability of the renewable generation that may use those lines.

Joint comments from the California Wind Energy Association and Large-Scale Solar Association. They believe we need to be focusing on optimal transmission solutions rather than on cost allocation issues. They also believe that generator interconnection tariff reforms should be implemented to address problems with the queue.

We received comments from Jon Seehafer. I'm not sure if I'm pronouncing that correctly. He is with the Department of Water Resources but the comments do appear to be his alone, not of the agency. He expresses concerns about offshore ocean energy that wasn't covered in the workshop. Because he believes it is on a development path to become something serious much sooner than the time it would take to place a transmission line.

And finally the joint comments by the municipal utilities. This is CMUA, IID, LADWP and

SMUD. CMUA members have a long history of successfully developing inter-regional transmission facilities. Many of these include participation by non-CMUA members and are jointly owned with other transmission owners in California and the West.

They believe we need a careful study of transmission requirements to meet the 33 percent renewable energy target.

That regional transmission planning should be accomplished through WECC.

That the initiatives discussed at the workshop are intended to be complementary but in fact they have the potential to work at cross purposes. Or at a minimum to duplicate efforts and delay resolution of key issues.

They believe that the WECC's Transmission Expansion Planning Policy Committee should be the umbrella organization.

And that joint ownership issues need to be resolved.

They identified some of the legal and market obstacles to that joint ownership. POUs require durable transmission arrangements such as bilateral contracts. The CAISO tariff is changeable in terms of transmission arrangements can be modified by legal filing at FERC. And these tariff modifications occur frequently.

The CAISO is moving towards locational marginal pricing, which uses financial rights, congestion revenue rights, rather than firm physical rights. And holding these congestion revenue rights can be risky and speculative.

The current CAISO tariff provisions require CAISO to have operational control of any jointly owned facility. CMUA understands that this provision is being interpreted to bar joint ownership unless the line is within the electric footprint of the CAISO balancing authority.

And finally, although there are existing examples of jointly owned transmission projects such as the California-Oregon Transmission Project and the Pacific DC Intertie, it appears that the CAISO is unwilling to use the existing examples of coexistence on jointly owned lines to be a model for future transmission development.

So just to quickly summarize the important points from this workshop. We heard again that transmission and operational constraints are the major barriers to achieving the 33 percent target.

RETI appears to be the front runner among all the initiatives. With the caveat that we need to figure out how to expedite the licensing of projects that come out of that process.

Also the CEC's corridor designation authority is going to be a critical piece. We need to coordinate the various initiatives to prevent duplication and conflicting results and also try to minimize the amount of staff resources needed from the various agencies that have to be involved in all of these initiatives.

We need to continue to address environmental costs and concerns as well as educate the public and local governments about the need for new transmission lines and the potential impacts and costs of climate change.

We also need to work with local governments to incorporate energy elements into their general plan. And we may need to move the planning horizon out 15 to 20 years to define long-term needs for new transmission, transmission upgrades and transmission corridors well in advance of renewable project development.

All right. So you have all been extremely patient as I plowed through all of this material in a relatively short period of time. So at this point I would suggest that that we take about a 15 minute break and get set up for the panel and then come back. And after we have the panel we'll have public comments.

PRESIDING MEMBER BYRON: Heavens no, heavens no. You may take a break.

Madame Chairman.

ASSOCIATE MEMBER PFANNENSTIEL: I just wanted to comment that I feel like I cut class and Suzanne went to class and took notes for me. And now I feel terribly guilty about cutting all those classes because it looks like they were very interesting. Thank you.

PRESIDING MEMBER BYRON: Suzanne, you did a wonderful job of summarizing a great deal of material. And we have made an effort to read through as much of this as we can and we have more homework to do. But I think if it's all right, you go ahead and take a break. I am going to suggest that we press on, unless I am causing any difficulty.

Those of you that were planning on a

break, take it now. But I would like to ask if we could go ahead and empanel the folks that are on the next part of the agenda.

MS. KOROSEC: Right.

PRESIDING MEMBER BYRON: And we will just press on. Because we have got lots of material. And I know it seems like you were up there for an eternity but it wasn't that long. It was very good.

MS. KOROSEC: You are very kind.

PRESIDING MEMBER BYRON: And please go ahead. And if those kind folks that have agreed to come and join us on this next panel. And I'll just ramble on for a few minutes.

Mr. Bartridge, are you -- I don't see a seat for you. Oh, you are going to be at the podium, wonderful.

And we only have 45 minutes listed for the panel. I guess I am a little concerned that that will be enough time. So I will give you a little more license on the time, Mr. Bartridge.

MR. BARTRIDGE: Very good.

PRESIDING MEMBER BYRON: But I would also like to speak to the panel members. We really appreciate your being here. This is an important topic that we want to get into. I was struck by some of Ms. Korosec' summary. The CMUA comments with regard to RETI slowing things down, need to streamline and consolidate efforts in transmission planning.

When people have asked me, how do we build a transmission line in California I have always said in the past, go talk to a publicly-owned utility. They can build a transmission line. But of course we have now managed to slow you down as well.

And we want to talk about this today. We want to get into the subject a little bit. And we appreciate your being here very much. But I am not sure that we have enough time for everybody to go on at length so we will count on Mr. Bartridge for keeping us on time. But I will also ask you if you will keep your remarks short. We will make sure we can get through some of the topics that you want to discuss.

Do we have anybody here from the ISO that is going to be joining our panel.

MEMBER OF THE AUDIENCE: They are going to be here at 2:30.

PRESIDING MEMBER BYRON: Ah, 2:30. So

we are supposed to take a break then, huh? You guys cut it close, don't you.

Well, you know what I am going to do then. I am going to ask if we can fill a little bit of our time with public comment, if that would be all right. And please, as I go through these you can defer until later if you wish. But I am going to take these in the order that I receive them. It is perfectly okay to defer. Manuel Alvarez from Southern California Edison is the first card that I have. I am not sure that I see him here.

MEMBER OF THE AUDIENCE: He stepped out.

PRESIDING MEMBER BYRON: Okay, no problem. And Victor Kruger, a senior transmission planner from San Diego Gas and Electric. Again, if you are here would you like to speak now or would you like to speak later?

MR. KRUGER: Maybe after the panel so I don't repeat anything.

PRESIDING MEMBER BYRON: All right, that's fine.

And Mr. Braun from CMUA. I'm guessing after the panel.

MR. BRAUN: Yes.

PRESIDING MEMBER BYRON: I knew it, I knew it. Okay.

Now there are some folks that are on the phone that may still be with us who may wish to speak now. And I am very eager to hear from Arthur O'Donnell, Center for Resource Solutions.

MR. O'DONNELL: I am here on the phone.

PRESIDING MEMBER BYRON: Would you like to speak now, Mr. O'Donnell?

MR. O'DONNELL: Well, I am just here to provide any background on the interactions between voluntary markets for renewable energy, especially the use of RECs, and compliance with RPS. And we were asked to provide some data and some insight to your staff. I didn't hear anything in the previous presentations that directly addressed that.

PRESIDING MEMBER BYRON: All right. Well thank you for being with us. We will then go ahead and hold off. You can reserve your right for further comment.

MR. O'DONNELL: Okay, thank you.

PRESIDING MEMBER BYRON: And also on the phone is Joseph Langenberg, Central California Power.

MR. LANGENBERG: I'd just as soon reserve my right to speak later, thank you.

PRESIDING MEMBER BYRON: All right. And then of course the other card I have, Mr. Charles Toka, wishes to speak at the end as well.

I think my plan has failed, I apologize. We are going to take a ten minute break. Thank you very much.

(Whereupon a recess was taken off the record.)

PRESIDING MEMBER BYRON: Ms. Edson, it is good to have you. Former Commissioner Edson. We were trying to press on without a break but couldn't do it without you.

I will now turn this over to Mr. Bartridge. Go right ahead.

MR. BARTRIDGE: Thank you, Commissioner. I will start with a little background here.

On July 17 representatives from Imperial Irrigation District, LA Department of Water and Power, Sacramento Municipal Utility District, Turlock Irrigation District and Western Area Power Administration met with Commission staff to discuss what they perceive as obstacles to joint transmission project development between POUs and investor-owned utilities subject to the CAISO tariff. At that time they presented us with a white paper highlighting these concerns.

The issue was then raised, as Suzanne noted earlier, during the round table discussion on our July 23 IEPR Update Workshop on transmission issues and barriers to achieving a higher level of renewables in California.

The white paper was submitted to our docket as an attachment to comments from CMUA on August 1. Some of the obstacles cited in the white paper as barriers to joint transmission development are operational, operational issues, financing issues, contract certainty, planning issues and ratepayer benefits.

In the interest of fairness I will also note that the CAISO has concerns of its own as it is charged by the Federal Energy Regulatory Commission not only with ensuring fair and non-discriminatory access to the grid but also in determining that proposed projects represent the least-cost solution for CAISO ratepayers.

So we are hopeful that today's panel discussion will shed some light on these issues and the parties can work together in the future so that joint transmission projects can be developed that will help meet the state's aggressive renewable goals.

I am going to lay out some ground rules for the round table as we get going. Let's start off with the POUs. And they will summarize their issues and the actions they believe are necessary to address them. We'll go for 10 or 15 minutes. At that point we will have a 10 or 15 minute CAISO response, followed by 10 to 15 minutes of interactive discussion, including questions from Commissioners. And thereafter we'll open it all up to public comments.

So with that let me introduce who we have today. I'll start with the POUs. Steve Sorey with SMUD, Mukhles Bhuiyan from LADWP, Juan Carlos Sandoval from IID, Randy Baysinger from TID, Laura Manz from CAISO and Karen Edson from CAISO. With that I'll turn it over to Steve to lay out the issues.

MR. SOREY: Let me start by thanking you for the opportunity to be here today. I will lay this out in a couple of big points. One is the issues we see with getting joint transmission projects done with California ISO PTOs. And then solutions that have worked for us in being able to get transmission built in the state of California.

Overall we believe that we need to move forward now with joint transmission projects if we are going to meet our renewable energy goals as laid out and the greenhouse gas goals. There is no time for delay given the challenges in getting these projects built. Environmental siting costs, location of renewable resources.

To accomplish this we believe we need to leave our philosophical differences at the door and come to the table and negotiate in a collaborative manner. We have growing concerns with joint transmission projects that involve the California ISO or California ISO transmission TOUs -- TOPs? Anyway, transmission owners.

We believe the ISO requirements for joint transmission projects present significant challenges to their development. We believe the ISO has stringent criteria in which any joint transmission project with the ISO requires, one, the assets be operated solely by the ISO regardless of location, regardless of percentage ownership. And two, once in service all operational costs, planning and expansion must comply with the California ISO tariff, regardless of any contractual agreements between the participants in the line.

These two criteria subject us to market changes or volatility changes in price, even though we have put hundreds of millions of dollars potentially into building these construction -- into constructing these transmission lines.

We believe the California ISO's narrow approach to transmission development restricts balanced bilateral negotiations among the participants and hinders joint transmission project development in California. The difficulty in developing balanced bilateral structured agreements with the California ISO has limited joint transmission projects among California ISO PTOs and non-PTOs to one project being completed since 1998. That being the Path 15 upgrade.

That project was taken on in earnest after the May 17, 2001 National Energy Policy Report recommended that President George W. Bush direct the Secretary of Energy to authorize Western Area Power to explore ways to relieve path congestion through the development of transmission. As a result of this a bilateral agreement was negotiated with the Western Area Power Administration, PG&E and Trans-Elect. After that negotiation the ISO adopted that agreement in whole with terms and conditions existing without modification.

Currently there are no joint transmission projects planned between the California public utilities and the California ISO. In contrast to that, development outside of California seems to move forward on a joint basis. On average Arizona utilities are building a new high-voltage transmission line and substation every 18 months. There is significant collaboration between the two investor-owned utilities and three public power utilities in the state. They use historical contract, bilateral negotiations to accomplish this task.

However in California we have not been as successful in developing joint projects between the California ISO and private utilities. For example, the Green Path Southwest and the Green Path North help to illustrate the challenges facing joint transmission development. The Green Path Southwest is a project IID, Citizens Energy and San Diego Gas and Electric attempted to build a 500 kV transmission project between IID and San Diego to provide access to renewable resources.

Another project, Green Power North. Green Path North, excuse me. It was a project between LADWP, IID, SCPPA and a nonprofit corporation, Citizens Energy Corporation. Attempted to develop an agreement for construction of a joint transmission project access for over 2,000 megawatts of geothermal resources.

Both of these projects failed. Our negotiations failed due to concerns and discussions over operational control and tariff issues. As I said earlier, we believe that joint transmission projects are needed more than ever to ensure that load serving entities achieve their respective mandated renewable portfolio standards and the future greenhouse gas standards.

Solutions need to be found to move beyond the current deadlock on joint transmission projects between the California ISO and other balancing authorities and transmission owners in the Western United States. Specifically we must constructively address the challenges created by the changing California ISO business model and that of its neighbors in the west.

In order to bridge the differences that exist between the California ISO business model and those of its neighbors a new framework which provides a balanced and evenhanded approach needs to be adopted.

This framework must include an open and non-discriminatory planning process. We believe that all planning should be done in accordance with FERC Order 890 and the WECC, Western Energy Coordinating Council, planning criteria.

Cost certainty. All costs and liabilities should be shared amongst the participants based on their investment and benefits received from the line.

Operational control. Day-to-day control should be negotiated by the joint participants, not solely under the control of the ISO by default.

For example, successful joint transmission project development that are moving forward: The Palo Verde North Gila Transmission Project is a 117 mile transmission line being developed by IID, APS, SRP and Wellton-Mohawk Irrigation District and will be capable of transporting 1200 megawatts of energy.

The Green Path North is moving forward but only with public power participants. It should allow access to renewable resources.

The TANK Alpha, Delta and Zeta transmission project, another one solely between public power entities, is a transmission line to be built in Northern California to provide access to renewables in Northeastern California.

In summary, we believe that a collaborative process is crucial to developing consensus and resolving these issues to ensure our efforts are better focused on achieving the state's energy effectiveness. Thank you.

MR. BARTRIDGE: Thanks Steve. With that we will turn it over to the ISO for a response.

MS. EDSON: First let me thank the Commission for holding this workshop and allowing us to be a presenter here. I am Karen Edson, vice president of external affairs at the California ISO. And to my left is Laura Manz, in her second week at the ISO as the vice president of market and infrastructure development.

PRESIDING MEMBER BYRON: Okay, we'll reserve all the difficult questions for her.

MS. EDSON: That's my plan.

MS. MANZ: That's why I'm here.

MS. EDSON: Laura actually brings a very rich background from the East. She worked for many years in an investor-owned utility in New Jersey interacting with PJM, ISO and more recently was an executive with San Diego Gas and Electric Company.

Let me respond at a high level and the same terms as Mr. Sorey. Because gosh, when I hear his list of requests, from my point of view it does not pose a real difficulty for us.

We are of the view that transmission funded by our ratepayers has to provide commensurate benefits to our ratepayers. In order to make that assessment though, as I am sure you understand, we need a project before us that we can look at, we can analyze, we can study to know what the ratepayer implications are, what the reliability implications are, et cetera.

We have provisions in our tariff that address many of the needs that Mr. Sorey described having to do with transmission ownership rights and actually minimizing certain charges and protecting transmission owners from other charges. In fact our tariff includes specific provisions that provide for the handling of bilateral contracts between the ISO and non-participants in our, in our market. And provides for waiver of transmission provisions when those agreements are accepted by FERC.

We of course are a regulated entity. A nonprofit, public benefit corporation and can't of our own action waive a FERC-approved provision. But that is an opportunity, I think, for engaging in very significant and important discussions about the kind of transmission projects that are being described here.

We do have very different models as you know. The municipal utility community reflects much more of the vertically integrated monopoly model that has existed for a long time. They also, like us, are nonprofit of course. And we are a market-based model so there are fundamental differences in how we conduct our business. Which raises an array of issues that should and need to be addressed in order to make projects of this sort go forward.

I think, as Mr. Sorey indicated, we should leave ideology at the door and try to make sure that we can reconcile these differences.

I do though want to make sure that we identify what I think is an important policy consideration that this Commission needs to consider. And that is to make sure that in the transmission development that occurs we are making sure that that transmission is fully utilized. So that before -- In order to make sure that we don't have to expand the transmission system beyond what should be the smallest environmental footprint possible.

These transmission corridors that need to be utilized are extremely difficult to establish. We all are aware of the kind of siting and permitting issues that have to be addressed. And it is I think quite important to make sure that the capacity on these lines is utilized for the benefit of the entire state in reaching these -- its important environmental objectives.

Laura, is there anything you can add in response?

MS. MANZ: One of the things that I think is interesting is that the ISO is not a changing business model.

ASSOCIATE MEMBER PFANNENSTIEL: Excuse me, would you make sure your mic is on.

MS. MANZ: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

MS. MANZ: And I will try to not holler too loud. We are not a changing business model. I mean, it is the Independent System Operator. It is trying to add scope and reach and more openness to something that was before this a closed process. And so under Order 890 we are obligated to open the planning process to all comers to look at what are the solutions. But that requires certain studies for reliability. We have to make sure everything works within the context of what's already there. So that's part of what needs to happen in a planning process.

Which I think everyone in the West is looking at how do we get better at doing this in a collaborative fashion. So if there is a changing business model I think that might be one of the directions we are headed is to have increased collaboration, increased dialogue around how this all works.

What I am not clear about. What does it mean to have cost certainty? And as roles sort of are separated and more clearly defined, as a transmission owner cost certainty means that you have sort of an annuity-style recovery for your transmission asset. And that's one style of cost certainty.

There is another style of cost certainty which as you are using the grid, either as a producer or a buyer, that you have some sort of way to risk delivery differences and delivery prices. And there are two models to do that.

One is a physical rights model, which means I inject a certain amount at Point A and I take out a certain amount at Point B and I know for certain what my costs are. We have a different price certainty model under our nodal pricing but it delivers the same thing. You have a right to inject so much at a certain point, a right to take out at a certain point and your delivery costs are hedged.

So under either model you get the cost certainty. So I wasn't quite sure, given those two things. I think we have cost certainty and we have ways to cover cost certainty in all cases. So I don't think we see anything from a conceptual or technical part that would stop us from coming up with something that would work for everyone.

PRESIDING MEMBER BYRON: Jim, I am going to count on you to go ahead and take us from here. You had said you wanted some round table discussion at this point.

MR. BARTRIDGE: Yes. I'd like to have some interactive discussion on this. If the POUs or anyone in the public would like to respond to the ISO's statements please feel free. I would like to begin a dialogue here.

ASSOCIATE MEMBER PFANNENSTIEL: Jim, may I ask a question? I just want to make sure I understand what these issues are that are in front of us. It seems to me that the publicly-owned utilities are saying to us that because of the way the ISO planning process and tariffs are set up that it is not feasible for them to join in joint transmission projects. And the ISO is saying, well show us one. Show us a project and then we will figure out how to make that work.

I don't know whether there are specific examples that the publicly-owned utilities can give me that would show me where projects have been brought to the ISO and it wasn't able to work.

MR. BHUIYAN: Madame Chairwoman, I am

Mukhles Bhuiyan with Los Angeles Department of Water and Power. I am a power engineering manager. I work in the power system activity office. We have -- In the City of Los Angeles we have an RPS policy. We have 20 percent within the year 2010 and 35 percent within 2020.

And we have been -- In the State of California we own about 25 percent of the transmission lines. In the past we have many, many joint projects that we could build, including the Pacific Intertie, Inter-Mountain Power Project, the Adelanto project. Those are multiple examples of public power versus investor-owned utilities that we have done. We have not been able to do a single one since ISO has took control of those entities.

I will give you one example. Green Path North is a transmission project we have been trying to build to get the geothermal power, which we believe is the only resource that can reduce our coal consumption. That transmission line starts from the station close to Devers. It is supposed to be a new station, Devers 2. And building a transmission line taking up to the new station called Hesperia close to Station Lugo.

So in that particular project we had Citizens Energy, a private entity, who wanted to become a partner with us. Everything was a go until they applied to CAISO to become a PTO. And CAISO's transmission revenue requirement asked them to be -- if they wanted to participate in this project the entire portion of that project, all power, although that is within our balancing authority. But because Citizen Energy as a partner wanted to be a participant in that project, the only way Citizen could participate, if the entire power was within the CAISO balancing authority.

So they have gone ahead, submitted to FERC. CAISO has intervened. And at the end they just gave up and they are not participating in the project anymore. They could not meet CAISO's requirement so we are moving forward. The municipals or the public power is moving forward with the Green Path just on our own.

ASSOCIATE MEMBER PFANNENSTIEL: So the ISO requirement that all the power be within the ISO balancing authority. That means control. Is it operational control that the concern was?

MR. BHUIYAN: Yes, yes.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you. Karen, did you want to respond?

MS. EDSON: Yes, I'm happy to respond. I was personally in several meetings with executives of Los Angeles Department of Water and Power where we made clear that we would not be insisting on the requirements cited here. We indicated an openness to discuss these things.

And in other conversations with Los Angeles regarding the kinds of issues that we would need to study were we to examine this project for inclusion in our rates, were advised that Los Angeles would rather not have those issues raised and would instead pull back from the project. So we are -- I hate to get into a he-said, she-said kind of conversation but we're left there to some extent by that particular example.

ASSOCIATE MEMBER PFANNENSTIEL: So your point is that in order for you to accommodate this project you needed to do a fair amount of more analysis on it and that LA and their potential partner on this didn't want to allow that analysis.

MS. EDSON: Well we have to be able to study these facilities and determine what the reliability impacts are, that they certainly have no adverse reliability impacts, and what the economic impacts are for our ratepayers. We have to make those findings, take the matter before our Board of Governors, before we can recommend to FERC whether the cost of these projects should go into wholesale transmission rates.

We have a very open Order 890 process. All stakeholders are welcome to bring these projects forward and to engage in that study process. We are open, as I indicated in opening comments.

ASSOCIATE MEMBER PFANNENSTIEL: On this one you weren't able to finish the analysis on either the cost or the reliability impact; is that right?

MS. EDSON: We were, we were asked not to pursue that work. And ultimately Citizens Energy withdrew their petition to FERC and stopped that process so the issues were not engaged.

MR. BHUIYAN: I will not get into the details. The only thing I will tell you is there are multiple e-mails that I have with me which basically says how CAISO has stonewalled the company and they had no other choice but to withdraw from the project.

And the submittal. Their submittal to the FERC process and CAISO's intervention into that will also speak for itself.

MR. SANDOVAL: I would like to add. This is Juan Carlos Sandoval from IID. I personally participated in the Greenpath Southwest negotiations for almost two years and our experience is pretty much the same. At the end of the negotiations the two issues that Steve described pretty much were the result of IID pulling out of the project. Basically operational control and application of the tariff.

But what I would like to say is I would like to look forward because we have projects, you know, like our Path 42 or others that can serve as an example. You know, how can we make this work, you know. We believe -- Personally I believe that public power is a key player in the solution to this problem.

PRESIDING MEMBER BYRON: Mr. Sandoval, the example you just referred to, would you elaborate. You said 532, I think. I forget what project you just mentioned was an example.

ADVISOR TUTT: I believe you said

Greenpath Southwest.

MR. SANDOVAL: Oh, Path 42.

PRESIDING MEMBER BYRON: Okay, Path 42.

MR. SANDOVAL: WECC Path 42 is our tie with Edison. Coachella Valley to Devers, 230 kV transmission lines.

PRESIDING MEMBER BYRON: And is that a previous example or a future example?

MR. SANDOVAL: Well it could be an example. That particular tie line between the two systems, IID and the ISO, can be enhanced and provide up to 3200 megawatts of capacity, you know, from the existing 600 megawatts and provide a lot of the energy to meet the RPS.

ADVISOR TUTT: And that enhancement would be the Greenpath Southwest Project?

MR. SANDOVAL: No, it would be -- Again, this is a WECC path, you know, that we have with Edison. It would build upon existing infrastructure that can be upgraded. We can deliver a significant amount of geothermal and solar energy from our system.

PRESIDING MEMBER BYRON: So this a future example.

MR. SANDOVAL: Yes, a future example,

excuse me.

PRESIDING MEMBER BYRON: The ISO has been around for ten years. The Path 15 upgrade I think was one of the examples that I read about. That the project, although unique, was successful. Were there other projects in the past ten years that are successful examples of POU bilateral agreement?

MR. SANDOVAL: Sure. IID is a participant in the Southwest Power Link. It was a joint collaboration between San Diego Gas and Electric and APS in building this 500 kV line from Palo Verde all the way out to the Imperial Valley Substation.

MR. BARTRIDGE: Clarify that.

MR. SOREY: That did not involve the ISO though.

MR. BARTRIDGE: Right, that is a much older project.

MR. SANDOVAL: Yes, it is in the past. Before, prior to the ISO. Excuse me, yes.

MS. EDSON: Let me, let me just comment on that because it is a preexisting project. It was prior to the ISO. But that's an example where we have worked with the parties to that agreement to make sure they can be accommodated under our model.

And just a note on the IID Greenpath Southwest Project. Which as I understand it was initiated as part of, an extension of the Sunrise Project I guess is a way to think about it. In part in order to give San Diego access to Imperial County geothermal.

In the case of that project IID would have been a five percent owner of the project with 95 percent of the cost covered by SDG&E and ISO ratepayers. There were some difficult conversations between all parties and there was a memorandum of understanding reached between SDG&E, IID and Citizens Energy. The ISO was not a party to that agreement but was well aware of it and was comfortable with it.

Subsequently a new Board of Directors was elected in IID and the district pulled out of that agreement. And subsequent discussions, as I understand it, were largely unsuccessful.

These things are complicated but I just want to assure the Commission that we are open to engaging in these discussions. We have an open Order 890-compliant transmission planning process and we think these kinds of issues need to come there. Imperial County is sitting on one of the richest renewable resources in the country and it absolutely is part of California's solution to its renewable objectives.

PRESIDING MEMBER BYRON: Yes. I don't think you were here to hear an earlier comment that it is the Saudi Arabia of renewables.

ASSOCIATE MEMBER PFANNENSTIEL: The Middle East.

MS. EDSON: If you count the solar in there I'm sure that's true.

PRESIDING MEMBER BYRON: The Persian Gulf of renewables but it has more conflict.

MS. EDSON: And less water. At least surrounding it.

MS. MANZ: I'd like to talk just for a brief moment about in theory what ought an Order 890 compliance process deliver for us and what the CAISO is looking for in the integrated planning. It is really I think a fairly simple threshold and not mutually exclusive from any other transmission owner. Job one is to maintain reliability and that is what we are all trying to do as we sort of collaborate on our plans for the region.

Job two is to make sure we aren't eroding any existing carrying capability on the system. So, you know, we want to make sure that if we build something it is robust enough to fit in to what everything else is already doing. So we don't want to build a small line that might take 1,000 megawatts of delivery and bring it down to 800. We want to make sure that the existing 1,000 becomes more when we build more facilities around it. And that's why this integrated planning is so important.

And the other part of this is, if there is a third-party private investor that wants to come forward and fund a transmission line. Again, this is an annuity model. Here is the tariff rate, here is what you will be paid. And it is important as we go through all this planning that we don't set up any barriers to entry to come into the process. But we also don't set up any barriers to exit if they find that it is not commercially viable for them.

PRESIDING MEMBER BYRON: If I may. The ISO wrote a report recently, I believe it came out about a month ago, indicating that if we are going to reach these high levels of renewables that we are discussing. This is really why we are interested in this topic. That we may need as many as six 500 kV lines that are built out of the desert southwest. So very simply, let's go. Why not? Let's build them and worry about, worry about filling them up later as long as they integrate with the system.

So I am trying to understand what the FERC requirement or the FERC role here is with regard to your tariff. Has something changed in the last ten years of the ISO's operation with regard to how you deal with these bilateral contracts or these bilateral agreements that the POUs come in with? Is it a new requirement that has been imposed or has it been this way since the ISO began?

MS. EDSON: I am not sure which requirement you are referring to.

PRESIDING MEMBER BYRON: Well, the operational requirement on the part of the ISO. The operational control and the tariff aspect. The wholesale tariff aspect that you brought up earlier.

MS. EDSON: Well no, the ISO has always had the obligation to approve projects whose costs were recovered in wholesale transmission rates for our participating transmission owners. That includes California's three investor-owned utilities as well as the southern cities and the public utilities there. And that requirement has always existed.

The opportunity to work with us and enter into bilateral arrangements is part of our existing tariff. I don't know, frankly, when it was, whether it has been there from the beginning or whether it was added more recently but I believe it's longstanding, our willingness to enter into these kinds of bilateral arrangements. And that can encompass operational control. I don't want to rule out those issues and there are various ways to define operational control.

All of those matters need to be part of these discussions.

ASSOCIATE MEMBER PFANNENSTIEL: May I just ask Mr. Sorey something on this. You said at the outset that there's only been one transmission project, one joint --

MR. SOREY: Project built since 1998.

ASSOCIATE MEMBER PFANNENSTIEL: And that's what I was trying to get to, the 1998.

MR. SOREY: That's when the California ISO started.

ASSOCIATE MEMBER PFANNENSTIEL: That's what I wanted to confirm. So your point is that it has never worked since the ISO has been around.

MR. SOREY: That's correct.

ASSOCIATE MEMBER PFANNENSTIEL: So it is nothing new and it is not some new problem. It has to do with whatever -- in your view, whatever the requirements are of the current ISO.

MR. SOREY: Right.

ASSOCIATE MEMBER PFANNENSTIEL: That it is simply not working for the munis.

MR. SOREY: That's correct.

PRESIDING MEMBER BYRON: And I believe Mr. Bhuiyan said that as well.

MR. SOREY: Yes. And if I may for just a second. It seems that we have two different models functioning here, our business models. One is the ISO's and it has various ways of hedging your transmission costs and your delivery costs and your energy costs. And that is a fair amount of complicated financial instruments.

Another is the way that has been done in the utility industry for a very long time and it is through contract ownership rights. You can inject power at one point and take power at the other end of that. Out at the other end at another point. And you know the cost of moving that power from Point A to Point B at that time and for the life of the line absent upgrades or changes. But you know what your cost to move power, for example, from the Pacific Northwest into California to deliver it to Sacramento.

Under the ISO's model you have varying instruments that allow you to hedge those type of transactions. You don't have any fixed costs other than the fact that you may have contributed to building the line and then you may recover that through other people using it. But the costs on those hedging instruments are unidirectional. So you may buy that or be awarded that hedging instrument in one direction. But if for some reason the LNP model is changing the dynamic of the system, you may get charged because you can hedge at the other direction. Those are the kind of risks we have difficulty taking on.

MS. MANZ: I would like to go back and talk about what's changed in the industry since 1998. And unfortunately I think I can speak to that issue.

ASSOCIATE MEMBER PFANNENSTIEL: Many of us have been around since then.

MS. MANZ: Yes. First of all what changed was the notion of open access. And it has changed more in some areas than others. But open access really means that you start with a fundamental model. And the model that the California ISO uses, the model that we are talking about today, really maintains that fundamental. I inject these many megawatts here, I take out as many megawatts there, and I size the wire to make that happen. That is not different between our model and the model proposed here, it's the same.

What is different is the open access and availability of the grid for people that didn't contribute to those initial set of rights. And so an ISO model will allow non-firm use of that system and people pay for the non-firm use. But the rights aren't courted. It provides you true open access. So if you are a load and you want to take more, or you are a generator and you want to produce more, you are allowed to do that even if you didn't have, you know, sort of a seat at the table in that initial contract.

But it doesn't erode what happened for people that had a seat at the table in the initial contract. So the model starts from the same place. But open access becomes sort of a grander concept, if you will, under certain conditions.

Another thing changed. And I sat in the dark during the Northeast Blackout and that changed fundamentally how we look at power grids. So, you know, sort of reading through the NERC Blackout Report, things like that, we really are trying to get a more regional view of things. And so what we are seeing in the planning process is to have more collaboration and to have more interaction, if you will, so that we have better scope, better reach.

I don't find it a failure to say, when we started open access we actually got better efficiency and better usage out of the grid assets that were already there. So I don't know that the fact that we haven't built. And I know we have built transmission. I think someone threw a number at me, about $8 billion worth, somewhere I have seen that. So there is transmission being built.

The question is, what sort of investment collaboratives work? What sort of reliability collaboratives work? What sort of planning collaboratives work? Because we have had a few things change since 1998. I think fundamentally how we think of open access and also how we think about reliability in a much broader scale have been kind of two fundamental shifts conceptually since 1998.

MR. BHUIYAN: I want to address a few issues that Ms. Manz just brought up. Open access. I hope many of you know that we do have open access. We have OASIS. We have built an OASIS everybody can access and post what is available for them. Which lines are available where they can transmit power from where to where. So it is not -- Our transmission has been built very robust and is not a closed system.

Secondly, you talked about energy prices. We, LADWP, has contributed with our excess energy during the California energy crisis. So we do have generation and we did, we do provide very reliable service to our customers. Our customers have not been blacked out, thank God.

Our company, along with all the other public power, I think we are -- As you know we are a vertically integrated utility. And we for ourself cannot invest money into building geothermal plants in the Imperial Irrigation District area or the Imperial Valley and not have the transmission built or the rights on transmission to bring that power to serve our load. That is the fundamental difference of policy we do have, to serve our customers. Thank you.

COMMISSIONER DOUGLAS: I have a question for both the ISO and the POU representatives. I am still trying to get to the bottom of the question of whether there is a fundamental obstacle here between using the ISO model for the portion of the line that pertains to utilities under the jurisdiction of the ISO and the POU model for the portion of the line that essentially is financed by the POUs and part of the POU systems. You know, I am hearing about the different models and how they might function differently. But fundamentally can you make those two systems work together or is it necessary that one system of either tariff or control dominate on the line?

MR. SOREY: There are several lines

today that are operated in this manner, with the two separate business models on the same line. And they include the Southwest Power Link, Path 15, Eldorado 500 kV system, the Malin-Round Mountain 1 and Round Mountain 2 lines. So it does exist, it can be done.

COMMISSIONER DOUGLAS: So from your perspective it is not, that's not a problem.

MR. SOREY: That's correct.

MS. MANZ: I agree.

MR. SOREY: I would like to address just a couple of things if I could, to respond to previous comments.

PRESIDING MEMBER BYRON: If you wouldn't mind, let the ISO folks respond as well then we'll come right back to you.

MS. MANZ: Yeah, I agree. I think we see a lot. Not only in the West but nationally there are, you know, these types of rights. There are wheeling arrangements where, for example, one I am familiar with is ConEd upgraded transmission facilities in its neighboring ISO. Not even neighboring utility, neighboring ISO. And it has rights to wield power through the neighboring ISO.

So you have these ISO or ISO market to

non-market interfaces. You have this creating kind of wheeling arrangements where you can do facility upgrades in your neighbor's territory and use the expanded capability. So there's all kinds of models that are workable under these, within these conversations.

COMMISSIONER DOUGLAS: So from your perspective then is it a negative in any way to look at a potential shared line as opposed to a line that would potentially be fully within ISO control or fully subject to the ISO-style tariff? Is there any disadvantage associated with a shared line?

MS. MANZ: From a funding perspective. Again I want to separate out the funding, the planning, the operating. From a funding perspective I think the ISO remains indifferent as to who is paying for lines that come in. We do need to make sure it meets all the reliability requirements and doesn't erode anyone else's existing transmission rights. That's kind of, I think we would all agree to that.

And then the other part of, what do we mean by open access. And if open access means that I build 300 megawatts of capability and I reserve it for myself and I don't let anyone else use it, then we would want something that's a little more robust that allows generation re-dispatched to increase, you know, capability. That we can have sort of shared use and more open use. And that's something that can be worked out. Again, all the examples we have given are situations where this can be worked out.

MR. BARTRIDGE: Commissioners, if I may. I would like to ask Tony Braun of the Municipal Utilities Association if he has anything. I see he is kind of jumping in his chair over here. And also Randy from TID if you have any input on TANK issues please add those as well.

MR. BRAUN: Thank you, Jim. Commissioners, Tony Braun on behalf of the California Municipal Utilities Association. I have a whole host of thoughts that are floating around in my head. Let's see if I can order them.

I like a lot of what the ISO is saying. I'd like to put a few points and specific examples on it to see if we can hone it and get some specifics here to make sure we are on the same page. I also think that it would be worthwhile to track down some of the examples that have come up to see exactly what happened and maybe we can avoid those problems in the past -- that have happened in the past.

Let's go to the Greenpath issue just to sort that out because I think we have sort of different scenarios. I am not burdened by being at the table in those negotiations so I would bet that from knowing a lot of what went on.

What I do know is what I read in FERC filings. And what I read is a filing that Citizens made in which they characterized, and I am using their words so I am not vouching for the accuracy of this characterization. That the facilities would categorically be required to be in the ISO's load control area for it to even contemplate the facilities for inclusion in the PTOs transmission revenue requirement. That's what they said at FERC. The ISO filed a response to that and it did not rebut that factual allegation.

So I think it would be helpful. I think a lot of what we are going on, what I am going on when I look at the barriers of joint transmission, is that specific point. If a line is jointly owned must it be within the ISO's balancing authority area, irrespective of division of percentages of ownership, et cetera, et cetera.

It just doesn't benefit and move us forward if we sweep that under the rug and don't get down to the specifics of it. And as this process moves forward I think it would be helpful to have clarity on the ISO's position on that. I don't demand it here, although it would be nice, but that's issue one.

The other issue is, what are these rights? Mr. Sorey alluded to several lines that are jointly, that ownerships are divided within the same physical wire. The California-Oregon Transmission Project, the DC Intertie, a host of others that are out there.

And the fundamental model for most of the public power entities, and certainly the folks at this table is, if they put down 30 percent of the cost of that line and their customers pay for 30 percent of the cost of that line, then the use of that line, that 30 percent, must be pursuant to whatever the terms and conditions for the use of that line are in their open access tariff.

That is their legal requirement but it is also their business model because they don't build transmission for that annuity revenue stream that Ms. Manz referred to. They build transmission to deliver their power portfolio to their load. So they need, they want the 30 percent. Whatever the benefits or the minuses of the financial model versus the physical model, they have adopted the physical model and that's what they need to go forward.

It is done today. It is not difficult. It is the result of agreements between the ISO and the other transmission owners. It doesn't require that the ISO have an opinion on how the cost of the line that someone else is paying for is being divided up as far as being used.

It doesn't require that the ISO have an opinion on how the other utilities' generation is dispatched. It doesn't require any of those complicated market things. All that is required is that the ISO, the portion the ISO uses be directly pursuant to the terms and conditions of its tariff.

And it can go through all of its processes so that it can determine the costs are outweighed for the benefit and it can protect its ratepayers. And the portion that the POU has an entitlement to can be operated and used pursuant to its rules and its open access tariffs and its legal obligations and also the obligations to its customer owners.

So there's several models out there. Clearly the perception on this side of the table is that there have been obstacles to that kind of model being used for future development and that those obstacles don't exist. If there isn't a requirement to substitute a financial derivative in lieu of the physical right for those types of development, if all the lines don't need to be in the ISO's balancing authority if they are jointly owned, then those are helpful developments that are going to move us forward but I think we need clarity on.

ASSOCIATE MEMBER PFANNENSTIEL: I agree, I think we need clarity on it. Is that clear? Is that agreed to?

MS. EDSON: I think clarity is fine and I think we have been clear in many ways. If you look at Section 17 of our tariff it provides very clearly that we are empowered to enter into bilateral agreements, either with non-PTOs or our PTOs from entering into those agreements. And if those bilateral agreements are accepted by FERC then certain provisions of our tariff can be waived. We need specific projects in order to be able to engage in those discussions.

PRESIDING MEMBER BYRON: Weren't there specific projects that were brought forward? The Greenpath, for instance.

MR. SOREY: Yes.

MS. EDSON: We are aware of those projects. I am not aware that they were brought into the study process that we have at the ISO. These require very careful, detailed studies and I am not aware that that actually occurred.

COMMISSIONER DOUGLAS: I understand that we need specific projects in order for the ISO to do its analysis about whether a joint line makes sense for its ratepayers in a particular situation. But in terms of the more general question that was posed, which is, is there an issue with a partition where the portion of the line that is POU-funded and pertains to the POU operational areas and so on is subject to the POU's rules, including its open access rules and the ISO's portion is subject to the ISO's rules. Whether that is an acceptable model. And I think

I have heard you say yes, actually probably multiple times.

MS. MANZ: I want to make sure we sort out a few things here. Because what we are talking about in all, as if it is one question, are many, many things. First of all we are talking about how you move electrons. And electrons don't know contract law, they only know the law of physics.

And so when we are talking about how do you manage the chain of custody for electrons from a generator through various control areas to the ultimate load, we have to track the electrons. We have to track the WECC and the NERC protocols about how you move them along. And that would be a problem whether you have an ISO or a non-ISO in the middle. There are protocols that have to be honored. There are operating agreements that have to all work together.

So I want to say yes, it is very doable. I am familiar with, you know, electrons that were generated in Chicago, had to go through the state of Ohio and a non-ISO to go back to another ISO in Pennsylvania. But you have to track how those electrons are being done because there's all kinds of like NERC reliability protocols that come along with the answer to that.

The next thing we worry about or that we overlay on the top of that is how do we price this. We are going to try to price this in a nodal way so that the value at every bus is known. And so we can write contracts that kind of make it unknown, and we can do that. Or we can make it a fixed price, and we can do that. But the finance is different than the chain of custody for the electrons.

And then there's the third question which is, open access. And having an OATT, an open access transmission tariff on file at FERC, is not the same thing as having a model that provides true open access where you can get generator redispatch service and things that aren't required under the pro forma OATT, if you will, at FERC.

So we have three different sets of issues for discussion. None of which are a deal breaker. None of which are a show stopper. But when we ask them in one long question it kind of seems easy. But until we take them apart and look at each one and say, this is a compound question.

And yes, we can do all of these things but we have to do them in the right forum.

MS. EDSON: And I do want to add that the joint projects we are talking about are not projects that are owned by the ISO. These are projects that are owned by participating transmission owners. If you detect a certain hesitancy in a response about how things like operational issues will be handled, it is because it is a bigger negotiation than just the ISO and the public power entities that might be involved.

PRESIDING MEMBER BYRON: It is workable, as Mr. Braun indicated, to have some -- I am not going to call it compromise, but you mentioned percent ownership and percent control. I think you used 30 percent. Is it possible to have bilateral agreements whereby that percentage of ownership of the, for instance, the publicly-owned utilities could maintain their own rights and agreements for that portion of it? Is that workable?

MS. EDSON: I don't want to rule anything out in this case. I think again there are multiple interests at stake here, including the interest of the generators who may want access to that capacity. It's not a simple question.

And in terms of the public policy issues it goes to the question of whether we are fully utilizing the transmission to the benefit of all of California. Are you making unused transmission capacity available for use when it is not being used by the owner? Now again, it is not our issue but it is a public policy issue and it is one that I am sure would be the subject of the discussions that we are talking about.

MR. BHUIYAN: Commissioner, if I may respond. You say, is it workable. Well, the joint projects that public power participated with the PTOs, which now is part of ISO, those are workable. Those are working because those have been grandfathered. It is the new projects that we are talking about. If we follow the same principle which has been acceptable in the past it's workable. Sure it is workable if ISO looks at that that way.

PRESIDING MEMBER BYRON: And those are of course the ones we are interested in, the new ones. An issue I haven't heard brought up and I was just curious if it plays here as well, and that is, public entities have access to low-cost bonds. Let's say lower cost interest bonds. Is that a requirement? How can I ask this? To get access to those funds do you have to maintain control? Could you not subject yourself to ISO tariffs?

MR. BRAUN: Let the lawyer take that. I'm not a bond lawyer but they are called private business use restrictions. And in order for the bonds to maintain their tax-exempt status for the bond holders there are fairly tight parameters and what can and cannot be done with the facilities that are financed with the tax-exempt securities. But that just means the rules need to be followed. That doesn't mean things can't get done.

Let me sort of bridge over because obviously there are municipal utilities that are participating transmission owners and have transferred their operational control of their segments of jointly owned lines to the ISO.

PRESIDING MEMBER BYRON: Right.

MR. BRAUN: One example, believe it or not. I guess it shouldn't be a surprise when it comes to transmission. These issues have been the subject of litigation.

When the second batch of municipals

asked to join the ISO, that would be Anaheim, Riverside, Azusa and Banning, the PUC and others actually argued that since the lines, a portion of the lines were in LA's balancing authority, the ISO didn't have physical control of the lines and didn't have other aspects of control such that the cost of the wires couldn't be recovered through the ISO's tariff.

And the ISO and the cities argued that, in fact, for all economic beneficial uses those entitlements on those lines, which are in LA's balancing authority, are under the ISO tariff. Everyone gets to use them pursuant to the terms of the tariff. And so therefore within the definition of the tariff the ISO has operational control.

FERC accepted those arguments. Those segments of those lines which are in Los Angeles' balancing authority are a part of the ISO tariff and are under operational control of the ISO.

So it is not a new issue. It's got a lot of application of lines that are all over the footprint of California extended electrically. We see those as very helpful templates on how to resolve this issue going forward. Well, that's what we said in our written comments.

Given what Mr. Balance has said and what the ISO's own studies say about the lead time of transmission and how to get to 33 percent and what we need to do, we should have started this a long time ago and we don't have a lot of time to get over, to have these discussions.

PRESIDING MEMBER BYRON: Mr. Braun, it is great to have you here. I really appreciate your input. Do you have any additional questions? Because I would like to ask if there's any more, Jim, that we should get to?

MR. BARTRIDGE: I think we need to wrap this up and look forward to public comments. If necessary we can continue this issue and continue this dialogue in perhaps an '09 workshop if necessary.

PRESIDING MEMBER BYRON: Okay. I want to ask one last question though of each side of the panel, if you will. And that is, do you see that we will be able to figure out some sort of workable solution to get these lines built? Because that is really what our goal here is in the long run; I suspect it's yours as well. Mr. Sorey?

MR. SOREY: Yes I do. And I believe that there are examples out there on existing lines. Granted they were grandfathered in. But that business model can work to promote joint transmission projects.

PRESIDING MEMBER BYRON: Okay. Ladies, do you think we are going to find a solution to this?

MS. EDSON: I actually think that we have to find a solution to this.

And one point I did want to make. I think it's important to put the development of new transmission in context. Because I think there has been the implication here that because there haven't been joint projects over the last ten years there is some failure. The discussions that have been cited I think are -- Let me put it this way. I am not sure there is a lot of value in going back and examining what are projects that changed over time and were the subject of a great deal of controversy.

The ISO has approved over $8 billion of transmission projects in California and more than half of those are actually built and in service. Those projects tended to be much smaller than the kinds of projects you hear about. They weren't Sunrise scale projects, for example. They were smaller projects that reduced congestion on the system and have lowered costs on the ISO system by more than $1 billion a year.

As Laura mentioned, the ISO model is one that does provide many important efficiency benefits. Having said that, we are open to have these discussions. Whether you can get the rights to use what you paid for. Is operational control actually essential for that to happen? No. Is operational control essential to us? It may or may not be depending on the circumstances and depending on discussions that have to include our participating transmission owners who are absolutely critical to have in those discussions.

PRESIDING MEMBER BYRON: Well thank you all very much. You know, just in the interest of time you are welcome to just remain seated there. Maybe there will be some comments or questions that will follow.

This Energy Commission is certainly willing to help where we can. But I think one Georgian-Russian standoff in the world at a time is enough. So I really appreciate your efforts to try and resolve these issues. And like I said, we'll be glad to help where we can.

Suzanne, should we move to public comment?

MS. KOROSEC: Yes. And we have Mr. Roy Kuga from PG&E who is going to be the first commentor.

PRESIDING MEMBER BYRON: That's right, I forgot, you have some already that are scheduled.

MS. KOROSEC: Yes.

PRESIDING MEMBER BYRON: Go right ahead.

MS. KOROSEC: Yes.

MR. KUGA: Good afternoon. Thank you, Commissioners, for allowing me to address you today. I would like to commend the Commission and staff for actually holding these types of workshops to address a broad breadth of complex issues, non-controversial of course. And I think they are very important in ultimately coming up with a comprehensive energy plan that serves the consumers of California with clean, reliable and reasonably priced energy.

I would like to address some specific questions that were raised earlier and also offer comments on certain, some of these points that

Suzanne walked through.

With respect to page four of the July 21 workshop summary, which was actually slide eight. The question was raised, how come there's so much cross hatching in these categories in the bars.

PRESIDING MEMBER BYRON: Thank you for remembering. Go right ahead.

MR. KUGA: And Chair Pfannenstiel also asked that we provide solutions or offer solutions, not just cite problems so I'll try to do that as well.

With respect to some of this cross hatching. A lot of it has to do with financing and the ability of the developers to move forward with financing. And therein lies a whole host of issues. From permitting and the extent that permitting processes in California. The site control issues to the extent it involves BLM. BLM has a backlog of about 130 sites for different types of renewable projects.

You know the rest, transmission, investment tax credits. But those are critical in terms of financing. The developers have challenges moving forward in getting financing for their projects unless they can demonstrate that there is transmission to deliver the projects on the scheduled on-line date. As well as they can meet the pricing requirements under the contracts which are dependant on your production tax credits, property tax abatements or investment tax credits or production tax credits.

Also what we see is projects have a greater success out of state relative to in California. And as a result certain projects migrate their resources, meaning their development resources or their equipment that were originally earmarked for California to outside the state of California because they can get those producing revenues a lot faster than within California. And also given that the market is rising and many developers pursue value-based pricing they can actually realize greater value than the contracts that are signed within California by developing and moving resources outside of California. So this continues to be a challenge for the entire state.

There are also issues related to, as was raised earlier, the rising cost. Which creates contract pricing pressures and challenges that the developers are unable to afford.

With respect to solutions. It is important that I think California adhere to the CEQA guideline of 12 months for the permitting review process.

The renewable energy zone concept I think makes a lot of sense. As you heard comments earlier it is important that we tie those to commercial transactions. I can say that, you know, there are certain renewable energy zones that have been identified. We in the past three solicitations for PG&E, for example, have not seen any bids from the Tehachapis. You know, you can designate a zone. Other utilities may have contracts but with respect to PG&E we are not seeing them.

PRESIDING MEMBER BYRON: Could it be, could it be because of the limitations or the requirements that are in the request for offer? We don't review those and look at them closely but if you are looking for firm resources they might have difficulty bidding them.

MR. KUGA: That's funny, it hasn't stopped, you know, 70 other developers from bidding in.

PRESIDING MEMBER BYRON: Seventy other

wind developers?

MR. KUGA: Including wind developers. So I would find that curious. First of all they have not indicated that to us. Second, we have seen developers for wind in other locations, both in California and primarily outside of California.

We have seen Edison most recently announce 900 megawatts outside of California, I believe from Oregon. They cited in one of their press releases that was one of the crown jewels of their renewable portfolio because the deliveries can occur much sooner. So we see a migration of contracting going outside the state because of the time to market and the time to deliver it.

And so it is important that we try to streamline the process as well as make sure we don't have duplicative processes by multiple agencies trying to address the same issues.

With respect to transmission. All I can offer is the perspective from the merchant or the procurement side of the business. By FERC Order 2004 I am precluded from looking at any of the transmission, non-public transmission information policies. So all I can speak to from PG&E is from the merchant perspective, the buying part of the business.

From my perspective, you know. We are making great strides. I applaud the ISO and the stakeholders for the RETI process and for queue reform and FERC for its support. But nevertheless if you look at the schedule, ultimately what it takes, what it probably will take to get major transmission in place under each process, we're talking somewhere between five to ten years. And more likely in the seven to eight year time frame. So we're talking about 2015 through 2017, '18, '19 as the time frame when some of these transmission upgrades will actually be in place.

So as we talk about accelerating, adding renewables, we need to keep in mind whether the transmission will be there. And counter-parties, the developers, are not willing to lock in the prices for ten years. They are not able to make financing commitments unless the transmission deliverability requirements are being met by their bankers or lenders.

So herein lies the challenge. The transmission process is moving forward. I applaud everyone for its efforts to accelerate it. We have to move fast though. And what can we do? I think it is important that we work with the entities. In some of the southern parts of the state it involves not only the munis but entities outside the state. Salt River Project, Nevada Power. To the extent the ISO can help facilitate us. And the developers moving forward with their interconnections. That would really break this upwards in time for the renewable element and deliveries.

With respect to some of the challenges that the developers are facing. I suggest you hold a workshop with the developers. Bring in the ones that have experience across the nation and across the world. What's working there and what's not working.

With respect to the comment earlier about permitted partnerships with transmission not being selected in the solicitation. I'd like to see that data because that is not consistent with the data that PG&E has seen. I have not seen a permitted project that has not developed with transmission other than an existing project. Those projects sometimes agree with PG&E, sometimes they choose to go with other buyers so I can't control that situation. But with respect to non-developed, permitted projects with transmission, I welcome them to show up, I am waiting for them. I haven't seen them.

With respect to -- I wanted to go to a supply curve here. And this is a simplistic illustration but indicative of the bids that we have received. But just to orient you, the Y-Axis is cents per kilowatt hour and the X-Axis is cumulative kilowatt hours. And these are representative of the bids that we have gotten in different solicitations from 2004 in the green, 2005, 2006, 2007.

We have 2008. I did not put them on there because we have not -- we are just beginning negotiations with them and I don't want to indicate where the pricing is at this point.

One thing to notice in terms of pricing. Pricing has more than doubled from the 2004 days. One phenomenon that is not shown here though is that when the MPR, the market price referent is set, prices tend to migrate to that point. The other phenomena here you see is that the supply has increased substantially in terms of what is being bid in. In 2008 our solar is reaching supply. And so relative to 2004 you saw the 2007.

At least a five-fold increase in supply. Potentially a doubling in price. So there is no shortage of supply.

Now what is not shown here is how much of these are dependant on permitting, how much are dependant on investment tax credits, how much are dependant on transmission. The vast majority are dependant on investment tax credits.

PRESIDING MEMBER BYRON: Absolutely.

MR. KUGA: A significant portion dependant on transmission and going through the transmission process. And notwithstanding the accelerated RETI process and the queue reform that could take a number of years. If you are in the transitional cluster in the ISO queue reform process that could take you to 2017 for transmission. How many people are willing to commit a price today with the hope that transmission shows up in 2017. So this is part of the challenge that we face.

ASSOCIATE MEMBER PFANNENSTIEL: Roy, you said there were several things that weren't shown on this. Well many things aren't shown on this. For example, the prices and the kilowatt hours.

MR. KUGA: By design. I am active in

negotiations with these counter-parties.

ASSOCIATE MEMBER PFANNENSTIEL: Well, but for the historical ones especially it seems like you could give us a clue to how many kilowatt hours are we talking about here and what are these prices we're talking about. And further it seems like that information should be available to us by technology.

I think that's exactly the kind of information that public policy makers need to have to be able to think about what is really working here. And we are not privy to the contract information. We don't really know. And I don't think we are especially asking for it on a contract basis but in some kind of significantly aggregated basis, especially historical. I don't know why we can't get that.

MR. KUGA: The megawatts and the gigawatt hours are provided with the CPUC quarterly RPS updates on the technology mix. They also describe what is in the current delivery system as well as what is under contract. Not unlike these graphs showing here what's pending as well as what has already been delivered.

ASSOCIATE MEMBER PFANNENSTIEL: Well

perhaps we'll actually send a data request to you for this specific information.

MR. KUGA: And as I indicated, the MPR is a good indication of where the prices have come in. I can tell you in 2003 the PUC said we'll accept everything up to 5.3 cents. So oddly enough the contracts came in very, very close if not exactly at 5.3 cents. As the MPRs have moved up, oddly enough prices have moved up in unison with the MPR price. So the MPR is a good indicator as to where prices are moving.

PRESIDING MEMBER BYRON: Or the other way around. This is helpful. And you said something, Mr. Kuga, that I don't quite follow. You said, prices have doubled. And of course not knowing the scale here. If I look at the slopes, the early slopes on these curves if they are representative, they are all pretty similar until they hit the inflection points. So what do you mean by prices doubling?

MR. KUGA: These are the curves --

PRESIDING MEMBER BYRON: And these are all real dollars these aren't constant dollars, correct?

MR. KUGA: Yes, they are in current

dollars so in the year bid. These are what's bid to us, not necessarily what we executed.

PRESIDING MEMBER BYRON: Sure.

MR. KUGA: And so I can tell you in 2002 we signed contracts at 5.3 cents or less. And, you know, prices are going up.

PRESIDING MEMBER BYRON: I'm trying to understand what you meant by prices doubling though.

MR. KUGA: Doubling. If you look at --

ASSOCIATE MEMBER PFANNENSTIEL: Is that the average?

PRESIDING MEMBER BYRON: The average of what you are procuring is doubling.

MR. KUGA: Not the average price that bid has doubled but the actual prices that we're negotiating and committing to are doubling.

PRESIDING MEMBER BYRON: Is that because you are procuring more? Because if you were procuring the same amount in all four of those years then it's certainly not doubling.

MR. KUGA: Not everything that is bid in is necessarily realizable. Not every bid is an executable bid, first of all. But what we are executing, prices have gone up substantially. And if you track the MPR and where the MPR has gone. Then you can also check for certain technologies.

PRESIDING MEMBER BYRON: I'm trying to understand what you mean by that. Because would you expect them to go down? If you are going to procure more in a given year then the slope of those curves would indicate the more you procure the more expensive those are going to be.

MR. KUGA: That's what these curves indicate. And so let's make sure --

PRESIDING MEMBER BYRON: Because these are ranked projects, essentially. That's what is confusing me is that you have ranked all the projects here in order of cost.

MR. KUGA: That's correct.

PRESIDING MEMBER BYRON: Right.

MR. KUGA: Economic theory will tell you as supply expands prices should drop. As you have more competitors in the market prices should drop.

PRESIDING MEMBER BYRON: But we also hear the argument that real construction costs have gone up substantially and that affects all industry, including this one.

MR. KUGA: Right.

ASSOCIATE MEMBER PFANNENSTIEL: That's

why I'm saying about technology.

MR. KUGA: But what I am saying also is you have existing projects bidding in as well as new projects bidding in. The cost to consumers of new projects and the cost to consumers of existing projects are convergent to the same number.

There is no distinction for something that was built five years ago or 15 years ago. We have irrigation district contracts, we have projects that were developed 20 years ago, 50 years ago. Very low cost to our consumers. Are they being priced as renewables? They are value-based pricing at where the MPR is. Or the extent they can get something higher they try to get something higher. So the prices for existing resources are doubling. The prices to consumers for new resources have doubled over time.

ASSOCIATE MEMBER PFANNENSTIEL: Would you give me an example. For example 2006 where we don't know what those units are. Where is the MPR in 2006 relative to that purple line? Is it right up at the top of the line, is it at the inflection point?

PRESIDING MEMBER BYRON: An illustrative MPR number, of course, to match the illustrative curve.

ASSOCIATE MEMBER PFANNENSTIEL: No, I want to know the actual MPR.

MR. KUGA: Okay, I don't have the exact number off the top of my head. Does someone here know the 2006 MPR? I want to say it was --

ASSOCIATE MEMBER PFANNENSTIEL: But I don't know what the units are here so that won't help.

MR. KUGA: Let's say it's 8.6 cents.

PRESIDING MEMBER BYRON: But we don't know where it goes.

MEMBERS OF THE AUDIENCE: That sounds about right.

MR. KUGA: All right, they said it sounds about right. Okay. So where is that? That represents a small portion of that curve.

ASSOCIATE MEMBER PFANNENSTIEL: So most of the curve is above the MPR?

MR. KUGA: Yes. So there's a lot of projects above the MPR. In fact the vast majority of projects come in above the MPR.

PRESIDING MEMBER BYRON: Well frankly I am not surprised by that. This is a different kind of resource than a natural gas resource.

MR. KUGA: Right.

ADVISOR TUTT: The fact remains though that most of the contracts that you actually negotiate with and sign are close to or below the MPR each year.

MR. KUGA: We take our time and we negotiate very diligently on behalf of our consumers.

ADVISOR TUTT: We don't know the scale of this chart.

MR. KUGA: By design.

ADVISOR TUTT: If you were to take only the lowest cost projects in each solicitation and that ended up to the left of the 2004 inflection point, generally, what you see is that in 2007 that black line in that portion of the chart is higher than the other years. I thought that was what you were talking about when you say that costs have doubled.

MR. KUGA: Well you can look at the average costs and you can look at the lower priced projects that we actually can see here. The costs have gone up substantially. And as I mentioned, there's a phenomena of value-based pricing, there's a phenomena of rising costs, commodity components, labor costs. So there are an array issues as well as the rising MPR. All right. More time than I expected to spend.

PRESIDING MEMBER BYRON: Well, it has limited value and we are trying to get more out of it than we can.

MR. KUGA: Right. But let me point out here. There was a comment in one of your earlier workshops about feed-in tariffs. And I had some opportunity to spend a fair amount of time to --

MEMBER OF THE AUDIENCE: Would you turn your microphone on, please. I don't think your microphone is on.

MR. KUGA: Okay. There was earlier comment about the feed-in tariff and I had an opportunity to spend some time with the Germans and the Spanish in terms of understanding their feed-in tariff. And basically where the feed-in tariff is in Germany for say rooftop solar systems, the equivalent in US dollars is 66 cents per kilowatt hour. For ground-mounted systems they probably get about 45 cents per kilowatt hour. For land-based wind about 15 cents per kilowatt hour, for offshore wind it's about 22 cents.

So what you would do is draw a line wherever you set the feed-in tariff and there would be, the difference between where that line is and what we are negotiating would be a delta that the feed-in tariff is set at that point. That's lost value to our consumers and basically profit to the suppliers. And so I just want to make sure that we are cognizant of the impact on our consumers should we consider a feed-in tariff.

ASSOCIATE MEMBER PFANNENSTIEL: Well that is assuming that we would set the tariff where it is set in Germany. I see no rationale for us doing that. We would set the feed-in tariff based on the technology needs in California. And that would not be totally indifferent from where you are along these curves here. So I don't think that we would necessarily have that kind of delta.

MR. KUGA: You can set it at a different price. But if you set a fixed price for each technology, what I am saying is the delta between the price that we are seeing through competitive solicitations and the price that is set through an administrative process, that delta is lost value to the consumers.

Now I think it is important that we try to understand what is it we are trying to achieve with a feed-in tariff. If you are trying to promote more renewables in the marketplace, unless you address the permitting issues and also address the ITC and the transmission issues, we are not going to see anymore renewables as a result of the feed-in tariff. So just to make sure we understand our objective here.

The other point of the feed-in tariff is it's a national program in both countries. Every consumer of every utility pays for it. There's no participants and non-participants. Everybody pays for a component. In the US the developers have these tax incentives and tax credits. That's on a national basis but every state seems to have a different renewable program. It's either 25 or 27 states have their own RPS standards. And it is not clear what California with a feed-in tariff would accomplish relative to what we already have in place with the competitive solicitations.

So I just say, make sure you understand what we are trying to accomplish and make sure we understand the considerations and the defaults of just going with the administrative permitting process. At this point that concludes my comments. I appreciate the opportunity to address you today. Hopefully I shed some light. I know it wasn't exactly what you were looking for on the graph but hopefully it was useful.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

MR. KUGA: Thank you.

PRESIDING MEMBER BYRON: Thank you, Mr. Kuga. Ms. Korosec, did you have someone else scheduled before we go to public comment?

MS. KOROSEC: Yes, Mr. Cazalet from MegaWatt Storage Farms.

DR. CAZALET: Thank you. At the outset in this hearing you mentioned the Governor's announcement this morning for 33 percent renewables. I think there is a burning question that storage is useful to achieving that. Given the size of that program we really have to find a way to get the gigawatts of storage on the grid, not a few megawatts. And perhaps we need to think about how do we achieve that by 2020 consistent with the 33 percent renewables target.

You held a workshop on July 31 and addressed many of these issues. CEC staff in particular as well as EPRI strongly supported storage for the various multiple benefits it provides. So not just for renewables. We'd need fast, clean storage on the grid even if we didn't have renewables. Renewables just increases the need for it.

Unfortunately during that hearing there were some comments made about a technology called NAS batteries that incorrectly described it as small. You need a lot of them to make a difference. In limited production, so we can't get them here to there. Expensive and dangerous.

PRESIDING MEMBER BYRON: What does NAS stand for?

DR. CAZALET: It's a technology by NGK of Japan. It originally meant sodium-sulphur, which is the combo that's -- I'll explain what that is shortly.

So the purpose of my appearing here today is to correct the IEPR record with respect to NAS battery storage.

Provide evidence that NAS is proven, available now in volume, economic and safe. And capable of meeting the needs of California.

PRESIDING MEMBER BYRON: Are you going

to provide an illustrative cost curve?

(Laughter)

DR. CAZALET: I'd be happy to answer some questions on cost.

And advocate that two to three gigawatts of this clean, fast and deep storage be deployed by 2020.

Now the slide from that workshop here, which I think was originally developed by EPRI under a contract with the California Energy Commission, notes a number of technologies. Starting with pumped hydro, which it says in five years it can go to 1,000 megawatts. To compressed air it says in five years you can go 500 megawatts.

Then it drops down to lead acid and NAS batteries, which it looks like we can build a very small amount in five years. Now these are the size of the individual facilities. As you go to the other batteries they are very small. Well first off, lead acid batteries are quite different from NAS batteries.

It turns out in five years I'm not sure we can site another pumped hydro. Probably ten to fifteen years if we're lucky.

Compressed air and storage. That's still a developmental project. I'm going to take at least five years to site that. Certainly the high volumes that we're talking about here. And it is not financeable at this point in time.

And for the NAS batteries. As you go up to the top, the real fact is that NAS batteries are one to two megawatts per unit and 500 megawatts of NAS within five years, for example, is very doable, contrary to what's said there.

So here's the first example. This is a wind farm in Japan that has just installed 34 megawatts of NAS batteries. Each of these batteries, they can produce 34 megawatts for seven hours.

PRESIDING MEMBER BYRON: So that's over 200 megawatt hours right there of storage?

DR. CAZALET: Yes, yes. And so that's on-line, working. It's a technology that is proven, commercial and being deployed around the world today.

PRESIDING MEMBER BYRON: That's an animated picture, isn't it?

DR. CAZALET: Well if you like -- I didn't take the time to do it but I have a movie of it.

PRESIDING MEMBER BYRON: No but -- Okay. They do exist?

DR. CAZALET: No, that is on the ground.

PRESIDING MEMBER BYRON: Okay.

DR. CAZALET: It is in operation. The next slide. That is just one of several installations in Japan.

Japan has over 280 megawatts on the grid. Some of it over to the right is the recent renewables projects to the total of just under 40 megawatts. But over to the left, they have been deploying this, particularly Tokyo Electric has been deploying it around Tokyo and other cities for a decade or more. Factories around Tokyo have 120 megawatts on the grid. They also have installed at malls, substations and other critical facilities around there.

Let's go to the next slide. This is an example of one such facility at a Hitachi factory in Japan. Eight megawatts. It doesn't look very scary. More like a park. That is eight megawatts times seven hours. Typically it has been used for taking off-peak power and delivering it on-peak.

Now these NAS batteries. You saw 34

megawatts at a wind park. That's one way to use them for renewables integration. There is no need in all cases for the batteries to be at the wind farm because you can locate them close to the load. They can still provide -- When the wind drops off they provide that power close to the load.

Tremendous advantages to putting the storage near the load. Less losses. We bring the power in at night when the wind is blowing. Deliver it to the customers in the day. The transmission lines have a problem we have got a reliable, local supply. These batteries, no emissions, no significant noise, no water, and you will see that they are safe.

So you can imagine a situation where you have hundreds of these renewable parks around California to achieve gigawatts close to the load, close to critical facilities where you need them defer new transmission or beef up the distribution system, provide local voltage support. An amazing resource. And it still provides what we need to integrate large quantities of renewables.

We are starting to deploy here in the US. This is a two megawatt facility going up with

AEP. AEP, one of the nation's largest electric power company, has made a major commitment to NAS storage. So it is not just the Japanese but AEP is going in this direction as well.

So now as to availability. The Japanese in the form of NGK committed to automated, robotic production of this technology back in 2003. This is a factory, a picture of the factory that has been operating since then. They currently have -- It is operating now at about 90 megawatts per year. And they just announced essentially a doubling in this facility, initially for another 60 or 70 megawatts going up to more like 180.

Basically this is a 6,000 square meter factory. You want to increase the production just build more of those factories. No reason we couldn't build a couple here in California and churn out batteries for the next two decades to meet our needs. At 200 to 400 megawatts a year pretty soon you get up to gigawatts on the grid.

The little white things you see on the assembly line up there at the top. That's the internal part of the cell. It's a ceramic element. The Japanese company that makes this is an expert in ceramics.

Down below you see the 400 cells in the module. The robots are welding it down there. I toured their plant a few months ago.

Over in the lower right corner you see an example of one of the batteries. In each of the vertical cases there's four modules or five modules. Each of the modules is 50 kilowatts, five modules is 250. You stack four together that's half a megawatt. You stack eight in a row, that's one megawatt.

So this is well-designed. The Japanese are very good engineers and very good and producing things that are reliable.

It's been on the grid in some cases for ten years, with actual operating availability of something like 99.8 percent. In use, on the grid. No other electric power technology for supply can meet that claim I don't think.

This is an example which gets to the design and safety issues. Each of those, each of those 50 kilowatt modules has about 350 cells in it. They make millions of these cells. The cell has a central core inside a tube. The cell is about that long with that much in diameter. Two to three inches in diameter, two feet long.

Inside the central core is a little tank with a tiny hole in the bottom with two layers of sodium. It operates at about 600 degrees Fahrenheit so in operational form it's like molten salt for the storage of solar. At that point there's a little tiny hole in the bottom where the sulfur can come out. The sodium can come out and go up an area that's surrounding the side to interact with the ceramic electrode and interact with the sulfur, which is on the outside.

It is all inside a solid tube, all completely sealed. They have got 400 of these sealed. So if any one of them broke it would be a small release of any of the materials. All these 400 tubes are packed in sand inside this container and stacked inside this vertically.

Extensively tested. We put a module in fire for some period of time, no problem. They burned individual cells, they crush it, they drop it. No safety problems. It's rated for installations in buildings in Japan.

NAS is cost-effective. When Tokyo Electric partnered with NGK in Japan to commercialize this technology 25 -- back in 1960 this technology was owned by Ford Motors in this country. They actually installed it in electric busses and cars.

But around 1980 they abandoned the technology. Tokyo Electric came and bought up the patents and spent $1 billion in 25 years refining the technology, building the manufacturing, testing it and getting it up to grid scale.

That's the kind of -- If we look at the technologies that are in the labs now, they have got to go through all those gates to get to something that we can install and we can get to the gigawatt scale. So the only way we are going to ever move with batteries on the grid right now is to import a technology like this until advanced flow batteries and others go through that same development process.

They claim their original goal was to make NAS batteries cost competitive with pumped storage. They have a large amount of pumped storage just like we do in California. Even more so in Japan. And they say they have achieved that goal. That goal has especially been achieved because when you build a pumped storage plant there is a big transmission investment to get it to the load. Here you put this NAS battery next to the load. Minimal transmission requirements. In fact it reduces your transmission.

Now when you look at any storage, in particular NAS, people often look at the cost per megawatt. And they make a mistake. Because what we need for renewables integration, for providing green ancillary services, is something that is dispatchable. So if I have got one gigawatt of storage that has two gigawatts of flexibility. Because I can be charging it and a second later discharging it. You get a two megawatt response in a very short period of time. You can't get that out of a conventional generator. So you get twice the hit there.

Then if you look at most conventional generators you have got to start it up before you can start moving it up and down. So a typical gas turbine might have maybe about 45 percent of its capacity available. So you get about another two X out of it. That gets you to four times the dispatchability compared to a gas turbine. And then by putting extra power electronics on these things you can get that up to perhaps a factor of six for shorter periods of time.

NAS has a much, much faster response than fossil plants.

And because it is difficult to site fossil plants in urban areas you have higher transmission costs. In fact, who was it who made the comment this morning that San Jose and San Francisco were saying, let's not build any more power plants in the Bay Area. You need more transmission. This would be an ideal solution to meeting the local needs using that approach.

Now the conventional approach is to use fossil fuels to back up wind. And wind varies, solar varies, a lot of other things vary. And as you ramp up these gas turbines up and down, or steam turbines or whatever, they produce a lot more than the average CO_2 and NO_x and other emissions.

A study which I can provide, the reference to it is on there, just out of the CMU says, combustion turbine backup of wind reduces expected CO_2 savings by about 20 percent. So if you are expecting to get X you are only going to get .78 X in terms of CO_2 reduction because you increased the CO_2 from an existing fossil fuel plant because you ramp them up and down.

It was a similar effect for NOx, which in some cases can be worse. Under certain conditions you are going to have to get more NOx out if you use a combustion generator to back up wind than if you didn't build the wind at all and just used the combustion turbine. Not all gas turbines work that way.

A study from KEMA says if we use storage to provide a frequency regulation we reduce the carbon emissions for that service by 70 percent. So storage is clean.

Now one thing that has come up already. We have more and more imports of renewables. What we have to make sure is that when we are importing the renewables the ancillary services and other services that we are using to firm up those renewables are clean. Otherwise we are just taking the problem of storage and clean, ancillary services and exporting it to other states that are perhaps using coal or natural gas to firm that up. so one thing to watch in terms of policy.

If we just deploy storage now to gigawatt scale. NAS batteries are available right now. That is going to encourage the investments in storage manufacturing for both NAS and others when it comes along when we see a large market and people are actually signing contracts.

It will lower the cost through volume production.

Promote commercialization of new, clean storage technologies that are further back in the pipeline.

Certainly we should continue to do the studies in new technologies. But the time for commercial deployment given the 33 percent renewables, even the 20 percent renewables standards and the other value of storage, is now.

So how can we move this along from a policy point? Last slide. The CAISO is working hard on adjusting their markets to fully utilize and fairly compensate storage services. And that is a work in progress that I am confident they will make and know where they need improvements.

One important thing is that if you look to the loading order you will start with energy efficiency and demand side management and down to renewables, et cetera. Storage isn't mentioned there. Now implicitly it would appear to be a demand side management technology, number two in the loading order. Making that clear in the procurement process I think would be very helpful.

The third one is, how do we -- You can think in terms of a feed-in tariff, you can think in terms of a portfolio standard for storage. Other countries and other places have talked about some of them. I propose one potential alternative. We currently have maybe seven to eight percent, I don't know the exact number in California, of pumped hydro as storage. Pumped hydro though is distant from the load and is also slow compared to -- you can't respond in a fraction of a second between full on and full off.

So then if it happens that the portfolio standard is say five percent of peak load by 2020, that would be a few thousand gigawatts of storage that is clean. In other words, it will produce no greenhouse gasses in the provision of the storage services.

It's fast. Because that's what we need for renewables integration, you need fast storage.

And it is deep enough to make a difference. It can be used for ramping and load following and diurnal shifting. Say you need six hours of storage.

Lots of variation but that would be one

idea for moving things forward. Any questions? Thank you.

PRESIDING MEMBER BYRON: That was very good. Any questions of Mr. Cazalet? Mr. Cazalet, thank you. I was thinking back, we have known each for about ten years. You brought us the automated power exchange and you were on the ISO Board for a number of years and now you look to be solving one of the great problems that we face in terms of large-scale utility storage.

Thank you for correcting our understanding here at the Commission. I am sure the staff is very interested in this initial information and I would expect that some of the providers of intermittent resources might be interested in this technology as well. So we will work on the valuing aspect of this. And I am sure that the IOUs present in the room here today are interested as well.

I don't know what else to say at this point except that your recommendations I noted. I think there's great opportunity. This is one of the things that we are looking for. One of the game changers that we are looking for to firm up resources with something other than additional, dispatchable, fossil-fired resources.

DR. CAZALET: You're right, it is a game changer. Many utility CEOs around the country see it as a game changer. What's incredible here is there is a technology they can apply today.

PRESIDING MEMBER BYRON: So thank you for bringing this to our attention. However, I hope that the rest of the public comments are not as commercial in nature as Mr. Cazalet's were.

Suzanne, am I okay to go through these?

MS. KOROSEC: Yes, please.

PRESIDING MEMBER BYRON: Manuel Alvarez, Southern California Edison.

MR. ALVAREZ: Good morning, Commissioners. Or good afternoon. Manuel Alvarez, Southern California Edison. I have two parts that I want to bring to your attention.

First let me address the issues that the staff brought up as part of their areas for potential study in the IEPR. There are five areas I want to emphasize that I think you should focus on in your study.

And the first one is identify and implement any actions to resolve the transmission issues involving environmental questions and land use issues. I think it is important that you address the issues of paths for new transmission routes and developing a process by which resolution of conflicts can be resolved. I know that is a daunting task but I think some of the tools that you are working on in your PIER program will lead you down that direction and I would like you to incorporate them in this particular IEPR.

PRESIDING MEMBER BYRON: Creating conflicts or resolving them?

MR. ALVAREZ: Resolving them.

PRESIDING MEMBER BYRON: Okay.

MR. ALVAREZ: We already know where the conflicts are developing.

The second issue I would like to keep on your agenda is the future cost of renewable generation. I think that is a critical component for you to keep on your agenda and present that information publicly so everyone can look and see where you are reviewing the cost of renewable generation.

The third item involves the contribution of meeting the RPS by publicly-owned utilities, community aggregators and ESPs. Just ensuring that the requirements and burdens of meeting that requirement are equally shared among all load serving entities in the state of California.

The next two items relate to transmission and technologies. We believe it is paramount that you keep the issue of emerging technologies on the transmission front as part of your IEPR. And look at those technologies and examine those new technologies that are coming before us in the future.

The next group of technologies we would like you to examine a little closer is the existing technologies. You heard one speaker before me speaking of the storage technology. We are looking for technologies that are on the threshold of commercialization or in fact have crossed over into implementation and activities. And that would include storage technologies and power electronics.

Now let me speak to the issue that was here in your panel. I was actually quite optimistic. And over the last few years since I have been dealing with transmission issues and transmission planners I have to believe that transmission planners are the most optimistic people in the world. With the daunting problems they have to face. They have to get up every morning and say they can still build a project in the state of California.

(Laughter)

MR. ALVAREZ: I am very pleased that your questioning of both the ISO and the publicly-owned utilities in finding resolutions to some of their concerns was receiving a positive answer so I am looking forward to those resolutions.

But the ISO is definitely going to be a participant in any future transmission expansion in the state of California. And the function of the ISO primarily is to facilitate the full and equitable sharing of our state resources on transmission and that's what they are trying to accomplish. So we support them in doing that activity but look forward to working with the publicly-owned utilities.

Saying that, Edison supports the joint planning process with all participants in transmission and look forward to that joint planning process. Where that forum takes place is an open question but somewhere and somehow the starting points of that process, the RETI projects are starting to take form and we are seeing that develop.

The next thing, you're aware, is the problems with transmission. And that's why I wanted to keep it on your attention for the IEPR. The issues of corridor expansion, right of ways, facilities. These are precious resources. They are not going to be easy to develop and they are going to have to be shared by all Californians in order to meet our RPS requirements and our reliability requirements that are in the future.

And that's why we think those resources should actually be shared by everybody in the state of California. And that one particular consumer should not be burdened with additional costs that other consumers don't have to pay. But it should be an equitable relationship on that transmission expansion.

The final thing I would like to bring to your attention is the joint use and how those costs and benefits are shared. We are basically supporting the notion that all customers in the state of California have a burden on this activity. It is no longer a system by which you have just one utility or one service provider paying those costs.

In order to get access to renewable resources Edison would have to cross into other service areas and would either have to figure out how to share transmission routes, transmission lines and operational parameters, or would have to build lines. I think you are aware of the difficulty of building a single line and that's why I think we need to push this joint venture planning. And if you have any questions I can answer them.

PRESIDING MEMBER BYRON: Thank you, Mr. Alvarez. That's as humorous as I think I have ever seen him before. Thank you.

(Laughter)

PRESIDING MEMBER BYRON: The next public comment. I have a card from Mr. Victor Kruger of San Diego Gas and Electric. One of those senior transmission planners who faces the daunting task of getting up every morning.

MR. KRUGER: I recently became a transmission planner just two weeks ago. I moved from operations, where I had the dubious honor of doing some of these legacy contracts and work with IID on the Southwest Power Link. I've administered that the last four years. Thankfully the Pacific Intertie has gone away from my perspective.

The point with that is, these contracts are really long-lived. So I am glad that CAISO takes these so seriously because decisions we make now on these joint transmission projects we are going to be living with for 40, 50, 60 years in some cases. So we like that the CAISO tries to fit these into their market design and their structure. And they are very detailed in their analysis, trying to look forward for the flexibility.

We have had some problems in the past with some of these legacy contracts. And that's just because of the change of paradigm before the CAISO and after the CAISO. There's nothing right or wrong with that. It's just a fact that if you have a contract the terms may not look or act properly 10 years or 20 years into the future.

So we rely, at San Diego Gas and Electric, on the CAISO to come up with a consistent framework that makes this work. We know we need joint transmission and it has to fit in such that we don't have people with dis-incentives. Some of the little quirks on existing contracts sometimes put us at odds that you can't exactly do what's right because of contractual problems with it. It is very difficult to work around those.

So one of the points is, we don't like special structures. If you have a framework, pick the framework. I'm not an expert on frameworks. They can work out. If they have a hybrid framework, if they have to use this framework or that framework. But they need a consistent framework.

And hopefully it can evolve over time such that as new things come up in the future -- who knows what is going to come up in 10 or 20 years. We may have bar markets coming up. And who knows how these bilateral contracts will do for shipping bars around in California, non-firm transmission and stuff. So we need that flexibility.

The other part is that California brings great benefits to all the stakeholders. I think they have done a great job taking a very complex transmission situation and coming up with a framework that works very well. It is not perfect for everybody. There are some stakeholders that re diametrically opposed on one issue from someone else. You can't please every stakeholder on every issue.

I think they have done a great job in keeping the playing field level. And we want to make sure that if we come up with some special structures to make sure this joint transmission does get built so we can get access to all the renewables. That the playing field remains level. That they can design something that is self-correcting over the long term such that you don't get the playing field out of whack.

So those are the main things I had to discuss with you.

PRESIDING MEMBER BYRON: Thank you very much. In the order that I received the cards I have on the phone --

MS. PARROW: Actually, all the phone people have cancelled.

PRESIDING MEMBER BYRON: That's a bad sign.

(Laughter)

PRESIDING MEMBER BYRON: There's only a couple of those so we still have a few more cards to go through. Is Mr. Steven Kelly still here?

MR. KELLY: Here.

PRESIDING MEMBER BYRON: Too bad you're not on the phone.

(Laughter)

MR. KELLY: Thank you, Commissioners. Steven Kelly with Independent Energy Producers Association. And I'd like to address two things. First I would like to address kind of this issue about contracts and some of the slides that the staff had put up and maybe respond to some of the comments I've heard from my former colleagues or my colleagues. And then talk about the transmission issues a little bit that was part of this panel.

On the first matter relating to the contracts. I was looking at the table that your staff had put up there that showed the status of those contracts. And you kind of asked the question, why is this occurring.

And first and foremost I want to say we evaluate the California RPS not in the context of how many contracts have been entered into. We evaluate how many projects have been energized and are delivering renewable megawatt hours to the grid. And when we look at a graph on contracts we say, fine. What I am really concerned about is the RPS. The fact that so few projects have actually been energized over the last years. Since 2002 basically.

And just as a notice to you. We have been very concerned about this for a number of years. We have raised comments about this. Yesterday we filed a motion at the Public Utilities Commission for them to investigate procurement practices in California that are designed to deliver the RPS megawatts and the reliability of megawatts that you might get from an all-source solicitation. And we hope they take that up because I think that is the only way we are going to get at some of these issues.

I am not privy to the information as apparently you are not privy to the information that would allow you to evaluate what is happening today. But we think that really needs to be done so that we can really get at the issue of why more projects are not becoming operational in spite of the fact that we have thousands of megawatts being entered into under a PPA.

ASSOCIATE MEMBER PFANNENSTIEL: Excuse me, Steven. What form did you file at the PUC?

Was it in the context of a proceeding?

MR. KELLY: It was a motion that we filed yesterday. I think it is in the context of a -- it accompanied our protest of the PG&E Tesla application and our motion to dismiss. So I am not actually certain which procedural vehicle we are using right now. It is just our motion to the Commission. And we hope they take it up as a broader issue beyond those two specific applications.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks.

MR. KELLY: I'd be happy to send you a copy if you'd like.

ASSOCIATE MEMBER PFANNENSTIEL: Yes.

MR. KELLY: It was served on the service list so it's out there.

Secondly I would like to talk about this cost issue. One of the tables, I think it was the table on number 11 on the graph that was put up by Suzanne shows the status of the supply curves. If you actually mapped across there what I think is today's MPR you would probably find out that almost none of those technologies are below the MPR if you look at the gross costs. It's when you look at the net costs, the real benefits to

California consumers, that you find out that almost all of them are beneficial when you do it that way.

But the problem you've got there is that the MPR is not at a level that your staff or hardly anybody else believes you can actually build new generation and deliver it to the grid. So I just make that as an observation.

And I have heard comments over the years and I heard comments today about the high cost of the RPS and how we have got to look at the bids and make sure that we use the competitive process to drive that price down to MPR and below.

I'll just make one observation. In the California RPS a REC is a REC. And that is used by the utilities for RPS compliance while the MPR is established around 11 cents per kilowatt hour I think for the marketplace. For everybody bidding in these RFOs. Which from all intents and purposes is not resulting in real, new generation being energized.

I will make the comment that this past year two of our Southern California investor-owned utilities have filed applications at the Public Utilities Commission to acquire RECs from their own projects. They happen to be PV rooftop-based projects. In those applications if you convert the amount of money that they are asking for for those projects with the megawatts, do a conversion to an energy deal, you find that they are asking for over 40 cents a kilowatt hour.

That is something that is not available to anybody else. It seems to be fairly comfortable with what Europe is playing on their feed-in tariff. And I would welcome and we have offered the opportunity to the PUC that we would deliver RECs at 90 percent of that rate as much as they would like. We hope they will take us up on that. So consumers will be benefitting ten percent for every REC they buy. Maybe that's a fair thing to get things rolling and see what can be actually built and delivered to the grid.

The important thing to note about the feed-in tariff. And I will just conclude with this thought. The comparison of what the feed-in tariff was, against the bid prices, is almost irrelevant. What's really a point of comparison is feed-in tariffs are paid once somebody is delivering a product to the grid. Not some speculative bidders.

So you want to compare the feed-in tariff rate that you have got with what it takes to actually get stuff built and connected to the grid. And I think evidence has shown it is not the MPR. The utilities believe it is somewhere above 40 cents a kilowatt hour. And we can start with that debate.

Now let me move to the discussion about transmission. And I want to make this over-arching observation. Delay is costing California consumers across the state a tremendous amount of money. You saw the curves. Costs are going up. Everybody recognizes that. Whether it's building transmission or generation or buying apples. Delay is costing consumers.

Now each individual sector within the state may be benefiting by delay but overall consumers are poor-advantaged by delay in building new transmission. It undermines state policies on RPS. It is going to end up undermining state policies on GHG reduction. And it may well have an effect on undermining RA responsibilities.

So we have got all these big state policies out there and we need transmission to get that done. And delaying transmission, you are just going to simply raise the cost to consumers statewide overall. And as a statewide planning agency that's probably where your perspective is coming from.

We have a couple of principles related to transmission and the transmission system as a whole. First, we don't think fragmentation of the transmission system is particularly good. We would like to see an integrated system.

Secondly, unused transmission capacity is also not good. Furthermore, a system that potentially could foster the development of phantom congestion for competitive purposes is particularly not good. I am in the generation business. I represent people who want to sell to the municipal utilities, I have people who want to sell to the IOUs, we would like to sell to everybody. But phantom congestion is something that we abhor because it keeps us, those people who can actually energize, off the grid. So we think that's bad.

And fourth I would just make the comment that building transmission in today's world and going forward almost requires that you build it as large as practical. Because we are going to have tremendous need. We can't anticipate how the RPS may grow over time and we have limited corridors. So that just begs for joint development of projects probably.

And the big question that I have at this point and I pose to you at the dais is, do we have to wait on the construction of transmission before we would resolve all of these control and cost recovery issues? And that's the big question. Because the more we delay the more costs go up and these delays could take a long time.

Is there a model or a mechanism that we can use today that will start the construction of the transmission as quickly as possible and then allow us the seven to ten years it is going to take to actually build that transmission line to resolve these issues related to cost recovery and control?

PRESIDING MEMBER BYRON: Isn't the answer to that question the third category of FERC tariff transmission lines?

MR. KELLY: Well I think it is actually, it's around the table here. I think it is the will to get it done. And we can resolve it at FERC if we need to, we can resolve it at the PUC or wherever. The issues of cost recovery, I think everybody pretty much agrees, you know, people who put in money for transmission lines should be reimbursed for that. Cost recovery should be not a question for anybody, including the utilities. If they put in X dollars they should know that they are going to get it back with a reasonable rate of return if that is part of their requirement.

The issue of control is something that is obviously a little more delicate. It is going to take some time to work it out. But if it takes seven to ten years to build a line before we have to even worry about who controls it, maybe we can start the line today and hope in seven years that we can resolve it. And maybe a little bit of arbitration might not hurt if people can't come to the table on that.

But I suspect over the interim period people are going to understand that we really need these lines to meet these policy goals and there is going to be growing incentive to work out some of these issues. But the important thing is to get the construction started as soon as possible.

I actually am thinking of something kind of akin to the old, I hate to say this, the DWR model. Where not so much the state intervened to do it but what was made was a commitment to have it done. And then a recognition that we are going to work out cost responsibility and those other issues down the road.

And that's what the PUC did with their investor-owned utilities in that matter. And they litigated it and, you know, it worked out. It took a long time but they finally got it out. Meanwhile we had the benefit of those generation assets during the time that everybody was debating how we were going to deal with it.

PRESIDING MEMBER BYRON: If cost responsibility were only the issue on siting transmission lines.

MR. KELLY: I understand. But cost responsibility is fundamentally important to people who are building transmission for purposes of expanding the transmission system. The other issues get to more important issues about how am I going to get my generation to load and so forth. Which is, in my view, somewhat unrelated to actually building transmission for public policy purposes today in California.

I understand that if an entity is building transmission lines to bring their generation to market they need a way to make that path there and some certainty that that's there. But if they don't use that capacity I am not too sympathetic that it remains unused while other people could use it. We've got to figure out a way to crack that nut.

So I have heard both, all the entities today talk about the need to use the transmission system in a non-discriminatory manner. Of course we support that. My members are probably the most directly affected by that issue so we will look to see the solution to recognize that. I think the ISO's current tariff provides for that. The munis have an OATT base mechanism, which I haven't heard complaints of yet. So there should be the nexus to make this happen.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

PRESIDING MEMBER BYRON: Thank you but one quick question. Back to what you said earlier when you were talking about the lack of contracts. I'm sorry, not the lack of contracts but the power that is being delivered. Aren't you really implicating some of your members companies when you question the lack of successful completion of projects on renewals?

MR. KELLY: Well to directly respond to that question. I suspect most of those aren't my member companies, they are more speculative bidders. The people that I represent have generation actually installed and they operate them and that's their business model.

The real problem is the people that are not getting selected who might be bidding slightly higher who have a lot of experience. And while I am not privy to a lot of information we of course hear rumors about that occurring. And I have heard rumors of that occurring. So that's one of the reasons we have asked the PUC to conduct an investigation to get at that issue.

Are there bidders that maybe don't need transmission or are slightly more expensive that for whatever reason have a really good track record of developing in California that aren't getting selected and brought to the table.

PRESIDING MEMBER BYRON: Got it. Thank you very much.

MR. KELLY: Sure.

PRESIDING MEMBER BYRON: Thank you for your comments. Mr. Craig Lewis, GreenVolts.

MR. LEWIS: Thank you, Commissioner. Craig Lewis with GreenVolts.

Sitting through this session today there were two things, two seemingly insurmountable challenges that came clear to me today. One is that transmission is a huge roadblock for the foreseeable future, certainly for at least the next five years.

The second is that it is tough to get transparent information out of the utilities, as if we didn't already know that. So what I am going to talk about today is a huge opportunity that overcomes both of these major challenges. And that is -- It overcomes these challenges to help us achieve the objectives of the RPS within the near term.

So I am going to talk about the wholesale distributed generation market. That is the market segment that is 20 megawatts or under. And we haven't spent a lot of time talking about that today but I would like to, I would like to open that up.

Also I would like to talk about the

feed-in tariffs and the ability for feed-in tariffs to really energize, really unleash that wholesale distributed generation market segment.

And thirdly I would like to talk about locational benefits. Those are the benefits of generating close to load. And that's what really helps us achieve. It puts this all together. It makes the feed-in tariffs work. Gets us up to a 20 cents per kilowatt hour rate and unleashes this market segment to address some of the issues that Steven Kelly just mentioned.

PRESIDING MEMBER BYRON: Mr. Lewis, the first topic, although as you know is near and dear to my heart, I would like you to make sure you discuss it as it relates to the topic that we are discussing here today. And that is the integration of up to 33 percent renewables.

MR. LEWIS: Yes, absolutely.

PRESIDING MEMBER BYRON: Thank you.

MR. LEWIS: I believe that addressing what is currently a market segment that has very little programmatic support, which is this whole distributed generation. If we put some programmatic support around that through a feed-in tariff vehicle then we are going to have tremendous amounts of renewable energy generation that comes on line.

And just to speak of that directly. RETI, when most people think of the RETI process, they think of dealing with transmission. The RETI Phase 1B Report that was released on Monday has a very interesting insight that basically calls out that there is 27 gigawatts of solar PV capacity available by interconnecting at substation locations.

So avoiding the whole transmission issue and basically just co-locating at the distribution substations they cull out 27 gigawatts. And that's limiting the project sizes to 20 megawatts. Now that's exactly what I am talking about except what I'm talking about doesn't -- you don't have to co-locate at a substation, you just have to be on the distribution grid. And you avoid the transmission issues.

So that 27 gigawatts, if you don't put the limitation of co-locating at a substation you are talking about multiplying that capacity by a factor of ten or more. I mean, it's really unlimited. So this opportunity, this market opportunity is really one that has been missed and it is tremendous in terms of meeting the objectives of the RPS.

What I would like to do is just talk a little bit about feed-in tariffs. I think that most everyone in this room is probably somewhat familiar with feed-in tariffs. But the key elements of the feed-in tariff are that there is a standard offer/must-take contract. That's what helps us get through the lack of transparency of dealing with the utilities.

Why should we have to deal with an RFO, an RPS RFO process for a small project. The RPS program was designed to offset 500 megawatt combined cycle gas turbine power plants. That's very different than a 20 megawatt sized renewable energy project.

By the way, GreenVolts is in a fairly unique position in this room because we are one of the few companies that has successfully navigated the RPS RFO process. We have our first deal that was approved by the CPUC. It is a contract with PG&E. We are happy doing business with them and would like to continue to do business with them, regardless of how my comments might sound.

But it was not -- Navigating that

process is not for the faint of heart. We have a two megawatt-sized deal. We spent hundreds of thousands of dollars on transaction costs alone. This is just simply proposing it, negotiating it, and contracting it. We are at least $300,000 into that process. And that does not leverage very well over a two megawatt size-deal. Let alone a 20 megawatt-size deal. Five hundred megawatts, yes, that's noise. But for 20 megawatts and under that's a lot of money. It really changes, it impacts the economics of those deals.

And really there is no need to do it. So the standard offer must-take contract is fundamental to a feed-in contract or a feed-in tariff. Really that is a programmatic solution that we need at this wholesale distributed generation, 20 megawatts and under.

Locational benefits I mentioned. I'll just speak briefly to those. GreenVolts has done an extensive study. We have utilized the E3 cost effectiveness model that was created on, was commissioned by the CPUC. And basically it identifies what the value of energy is depending on where you are generating it respective to the load.

And in California, on average, if you interconnect on the distribution grid, your energy is worth 35 percent more than if you interconnected transmission on the transmission grid. So we have done an extensive study. We filed -- We've had a filing with respect to the MPR workshop several months back that identifies that study and has the results in it. We'd be happy to share it with whoever wants it.

But basically if you take a look at those locational benefits and you start constructing a feed-in tariff that has a rate that includes obviously the MPR. We already have a feed-in tariff that is priced at MPR. If we add in the locational benefits value of generating close to load then we are basically getting up to somewhere in that 20 cent range, 20 cent per kilowatt hour range. When we hit that magic number we unleash the tremendous opportunity that we have here in the wholesale distributed generation market. We need to get up to about that 20 cent per kilowatt hour.

I think that the 2007 MPR was somewhere, it's basically nine and a half cents. We are hopefully going to get a 20 boost to that in the

2008 MPR. We'll find out here around September 2 as I understand. But basically if you look at that plus time of delivery factor and then add on a 30 percent or so locational benefit adder onto that you are essentially at 20 cents per kilowatt hour. And that is the magic number that really unleashes this wholesale distributed generation market.

So the feed-in tariff that I am recommending that the CEC really study and think hard about introducing and recommending is a feed-in tariff that would cover 20 megawatts, 20 megawatt sized projects and under, and would be priced at MPR plus TOD plus locational benefits value. And that hits the magic number to unleash the vast potential of the wholesale distributed generation market.

Thank you and I'll take any questions.

PRESIDING MEMBER BYRON: No, those are very good comments. Thank you very much for your input. Thank you for enduring with us this afternoon to provide them.

MR. LEWIS: Sure.

PRESIDING MEMBER BYRON: I have a couple left. I believe this is Tandy Mannes or McMannes.

MS. KOROSEC: It's McMannes.

PRESIDING MEMBER BYRON: McMannes, forgive me.

MR. McMANNES: Currently I work for Abengoa Solar; I am in charge of project development. Prior to doing that I spent 22 years working with the solar projects in the Mojave Desert. And the reason I say that is because I believe that I know how much it costs to, you know, build, own and operate solar projects. Certainly 20 years ago. And I also believe I know how much it costs to build, own and operate them today.

In order to really solve the problem as to how we are going to achieve 33 percent renewable I think we need to clearly define what the problem is. And we can all disagree. But when I hear my friends at the CPUC saying that the RPS is going to work and it is robust and it is going to result in the 20 percent or 33 percent renewable I become concerned.

Suzanne, can you put up that same chart, the contract status chart.

I believe we are going to continue to see more and more contract failure. And the reason I believe that is because the IOUs are for whatever reason, and I'm sure there's good reasons. They are short-listing and accepting low-cost bidders. Now those low-cost bidders, as someone I think pointed out and Roy pointed out, they tend to track the MPR. Which makes a lot of sense. If your goal is to win a PPA or be awarded a PPA, you want to be able to track at or near the MPR.

In the goal of trying to achieve a PPA what you are really doing is trying to stay alive. There are a number of developers that don't have large balance sheets. Maybe like the company I work for or the company I previously worked for. And they really do need to attract investment capital. So what is happening is that after achieving this PPA they don't necessarily have the financial resources or the ability, like Roy pointed out of PG&E, they don't have the ability to finance these projects.

What I would like the CEC to do is have a forum that you can actually call in a number of developers to actually talk about contract failure and actually do an analysis of contract failure. Because I believe it is going to continue to happen.

I commend the CPUC for attempting to make the MPR as robust as they have. It has come up over the last several years. They have added the GHG adder. But as long as the IOUs continue, maybe through their own internal policy or the policies of the CPUC, to accept the low-cost bidder, you are going to continue, I believe, to see this contract failure.

So if we had a forum where developers were able to come here and be able to analyze that failure. And maybe we'd begin to understand what the problem is. There is probably no one answer to the problem. But certainly to say that the RPS is going to result in the 33 percent renewable is just not correct. Not with my 22 or so years of experience in terms of project development. So those are my comments for today.

ASSOCIATE MEMBER PFANNENSTIEL: Mr. McMannes, can I just ask. Part of what we are struggling with, and I think you have heard it today, is the lack of transparency in the information. We know what the MPR is but we really don't have much sense of what the bids are or what the PPAs are for or where the developers fall off in terms of these prices.

So if we had some session. And you are actually the third person today who recommended that the Energy Commission bring the developers together to talk about this.

Would we be able to get from the project developers more of a sense of the costs and where they are going on the bids? We kind of feel like we are all looking at Roy Kuga's graph without numbers here. You know the prices are up and you know there's more quantity but you don't really know where you can go with this.

MR. McMANNES: I don't really know how to best answer that because the conversations that I have with the utilities are confidential. But I can certainly support what Steven has said, you know, wholeheartedly. He's right on on his statements. I'm not saying that those project developers that don't have the balance sheet are not intending to build projects. What I'm saying is that they are having to go through a couple of step process.

When you have companies like mine with a balance sheet and they're building projects in Spain and they're building projects in Africa.

And you've got the company that I came from, FTL Energy who, you know, also has a balance sheet to build them and is capable of building them the question you ask is, why. Why aren't they the ones getting the PPAs?

I guess I need to talk to our attorney and see what information I can provide you and what I can't. Maybe those are some of the rules that we need to work out in advance of that forum to kind of put numbers on Roy's schedule.

I guess another thing. Before I leave I wanted to comment that there have been two models for success. The first model was the standard offer contracts in the mid-80s. There was both the tax legislation in place, which we hope to get, you know, sometime next year, and there was, you know, the transparency in the numbers that you are talking about.

Now if you had the same standard offer contracts today the question is, would you need an oversupply. You would certainly get an oversupply of bids probably but you wouldn't get an oversupply of generation. So we need to kind of understand how that works.

The model that works currently in the

rest of the world is the feed-in tariff like somebody had talked about. You know, you have the feed-in tariff in Germany that works. You have the feed-in tariff in Spain. And I guess where I agree with a lot of the comments that Roy made, the one I would have to disagree -- you know, clearly you wouldn't set a rate in California that you set in Germany. In Germany they don't have any sunshine. They have a little more in Spain. The best place in the world for sunshine is the Mojave Desert in California or the Southwest so the rates would be significantly lower.

But you need to have that type of transparency because then you would get companies with the balance sheets to bid. And I asked myself, if I have land and I have transmission and I have water and I have a balance sheet. I have everything it takes to get a project built but yet I can't get a PPA. Then as a developer, you know, it could be sour grapes that those other guys are getting them and I'm not.

And I hope that they can build but I think we are going to find that there's going to be more and more contract failure. And then that's where I think we need to have our analysis to get to the root of the problem.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

ADVISOR TUTT: And Tandy, can you say whether you are actually bidding into the RFOs for these?

MR. McMANNES: We are spending lots of time bidding. We were bidding all over the Southwestern United States. IOUs and POUs and, you know. If someone was looking for generation we bid into that. As you know we did sign a contract in Arizona with APS.

The one thing I can say about the contract in Arizona was APS was not subject to an MPR.

PRESIDING MEMBER BYRON: I'm not an attorney but I did read yesterday, as I indicated, in a sample RFO, that there's non-disclosure of the fact that you bid into that RFO.

MR. McMANNES: Well the only reason why I can say that is because we were awarded the contract and the press has made a lot of, you know.

PRESIDING MEMBER BYRON: Yes. I am not saying that you did anything wrong.

MR. McMANNES: Right.

PRESIDING MEMBER BYRON: But it is just so much information that I think is unnecessarily protected in the so-called public interest is really inhibiting the transparency of this process.

MR. McMANNES: Not only is the information publicly protected but it is often mis-stated. When I read in the newspaper about what the price that I received from APS and I'm thinking, that's not the correct price, where did they get this information. So what you read in the press is wrong. And what you don't read in the press, you're right. You can't disclose because it is not for the public. And it produces a lot of disinformation.

PRESIDING MEMBER BYRON: Mr. McMannes, thank you for being here and thanks for your comments.

MR. McMANNES: Okay, thank you.

PRESIDING MEMBER BYRON: Ms. Nancy Rader, California Wind Energy Association.

MS. RADER: Good afternoon. Nancy Rader, California Wind Energy Association. I find myself wanting to react to a couple of things before I say what I came up here to say.

I have to disagree with my friend Tandy and Steven. The view of CalWEA's members is that the RPS process is working. It is producing financeable contracts. And that we really need to rely on a competitive mechanism to procure major quantities of renewables in the state to protect consumers and to ensure that they are going to pay the least that they need to pay for renewables. We don't want to see a backlash about the cost of renewable energy.

The problem is lack of transmission, the focus of the panel today. That is a problem. And it accounts probably for some of the contract failures and renegotiations. Because let's face it, prices change while you're waiting five years for transmission to get built. If we had sufficient transmission capacity in the state we would have a much better, fluid market because people could get to market. People cannot get to market right now and that's a big problem.

We think we achieved a big milestone with the ISO's interconnection reform process. That's the biggest problem today is that huge backlog in the queue. It's going to take a couple of years to work through that but we are pretty pleased with the reforms the ISO is putting into place.

We hope that the RETI process will help give us a jump start in that process by identifying some of the key backbone corridors we need to upgrade and hopefully that can jump start the upgrades that come out of the LJIA process.

I wanted to react a little bit to what Mr. Cazalet was saying about storage. We agree it is important to look at the load storage in achieving 33 percent renewables. But we want to note that it is never efficient to plan or operate storage in conjunction with certain generators or certain loads. It is always more efficient to plan and deploy storage on a system-wide basis. So instead of talking about renewable storage probably we should be talking about how storage can improve system efficiencies and meet system needs.

And likewise talking about backing up wind. It doesn't make a lot of sense. Nor does the fact that renewables operate in a large system like all other resources and loads. A very diverse system that to a large extent other resources complement each other. So again we need to focus on operating the system efficiently rather than backing up particular resources.

And that relates to the point I intended to make which was the importance of the Independent System Operators in growing renewables in California and across the country. Independent System Operators are playing a really critical role in the development of renewables by providing non-discriminatory, open access to transmission and by providing superior capabilities and the services that are needed to integrate renewables, such as ramping capabilities.

By their nature larger operating systems create a larger pool of resources that can be used to balance each other and which facilitates renewables integration. In addition the hour-ahead and day-ahead markets provide the best means of addressing the variability of wind output. And these characteristics no doubt account for the fact that about three-quarters of the country's 20,000 megawatts of wind have been built in ISO or RTO systems. Which is disproportionate to the wind resources in those areas and the loads in those areas.

So the wind industry views the ISO's policies as very important to achieving 33 percent renewable goals and we are very engaged in the ISO forum. We have put a lot of time and effort into its interconnecting reforms. As I said, we feel it is successful.

And we think that the ISO's renewables integration study is going to be a very important focus in determining what we need to manage the 33 percent renewables and how we might get there. For example, the ISO can create the market signals that we need to ensure that we'll have the appropriate ancillary services we need to incorporate 33 percent.

And without those kinds of mechanism we will obviously have to plan to meet those needs in other ways but we are very hopeful about what the ISO market is going to do to achieve 33 percent. Thank you very much.

ASSOCIATE MEMBER PFANNENSTIEL: A quick question. You stated that the contract failure problem is really just a transmission problem. You don't see it as a siting? Others have commented that, and I think it might be true of the winder developers as much as anybody, that there are just local siting issues and that kind of problem that delays the projects.

MS. RADER: Siting is certainly a challenge in California. And I think to a large extent -- I think one of the utility commentators mentioned that they are seeing a large increase in the number of bids. I think we have built up a lot of momentum in the state. We were moribund, you know, when the RPS was passed in 2002. There was nothing going on here. There were almost no developers doing business here. Now our membership has tripled. The activity in the state is just incredible.

And it takes years to work through the siting processes. It takes years to get through the ISO queue. We are just starting to see really everything starting to get into place where we can now actually get things going. And I think obviously that transmission is the linchpin. We simply have a disconnect in the supply and the demand. And until we overcome that we are just not going to have a very good market.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

PRESIDING MEMBER BYRON: Ms. Rader,

thank you. I assure you we are trying to remove these roadblocks, not trying to add new ones.

MS. RADER: I appreciate that and I think we are moving in the right direction.

PRESIDING MEMBER BYRON: Thank you for your comments.

MS. RADER: Thanks.

PRESIDING MEMBER BYRON: I think I have two left. We'll go with two and then we'll check. Mr. Harris, Bright Source Energy.

MR. HARRIS: I guess it's good evening now.

PRESIDING MEMBER BYRON: We should be clear, Mr. Harris. You are an attorney who represents a number of projects under development. In this case you are representing Bright Source Energy.

MR. HARRIS: That is correct. Although if you want questions for Citizen Harris at the end I'll be glad to answer those as well. But I am here on behalf of Bright Source who have a project. Obviously respecting that process I am not going to talk about that project.

My comments are more generic and I do want to focus on three things really and the first one is permitting. There was some discussion of that. The second one is transmission. Although that equine is suffering badly. I don't think I am going to beat on that at all really. I'm going to go through that quickly. And then mitigation issues. I'm going to talk a little bit about that. That's one thing that hasn't come up today that I think is an emerging issue that this Commission is going to have to wrestle with and wrestle with your federal partners. So more fun stuff to look forward to.

Taking to heart the question of hurdles. Permitting is really the issue in my mind in California. We have a lot of projects going forward on federal lands or with federal nexus. That then requires a NEPA process as well as a CEQA process. NEPA and CEQA both encourage a joint process. They encourage a joint document. Applicants encourage a joint process and a joint document. It's just more litigation and more paths for procedural madness if you don't keep those processes together. So we are very happy with the Commission's decision to try to make those things work together.

But having said that, there's a pretty

serious mismatch between NEPA and CEQA generally. And when you add to that the additional complexity of the fact that this Commission operates with a certified regulatory program, not a typical CEQA process. You don't produce an EIR document, you don't produce a draft EIR or a final EIR.

Aligning those CEQA and NEPA processes gets to be all the more complex. And believe me, we have got some very good minds in my law firm who spend a lot of hours just trying to get down to basic, legal parameters for the NEPA compliance and compliance with your processes. If I had a quick, simple answer I'd both patent it and share it with you. But I don't so we'll just continue to work with you on that.

There are a couple of things that I do want to suggest to you are very important fundamental things for this Commission as you process these applications moving forward. The first one is being able to work on NEPA and CEQA issues in parallel and not sequentially. It is very important that you take advantage of time overlaps.

And one of the things that applicants are concerned about are these various deadlines being lined up, you know, head-to-toe, head-to-toe, stringing out for what becomes years literally in those processes. So we are going to need to work with you all to figure out how to shorten those time frames. And really, you know, that's my bumper sticker for the day. In parallel, not sequentially.

The Commission is also going to need to carefully distinguish between real, statutory and regulatory deadlines. With 30 days for comments, 45 days for comments, 90 for comments, and internal processing deadlines. And in my view those issues have kind of gotten melded together and they need to be separated very carefully. And that I think will help with the idea of putting things together in parallel instead of sequentially.

And we will propose eventually, as an industry, schedules to kind of figure out what is a real, hard deadline and what are the kind of things that maybe with a little moral suasion, you know, you're discussing with your federal partners, you can move things along, you can help move things along because they are not statutory 45 day or 30 day deadlines.

And there's several of those things for these processes, even if they are going to go forward as a single process, which we definitely want. You're going to have to couple and decouple these processes. And I'll give you a concrete example just to, you know, so it doesn't sound like a train analogy.

When the FSA is ready for a project your process can move forward at that point. There may be because of the federal processing requirements some initial time that has to happen on the federal side. There may be some internal reviews. And ultimately their process is kicked off by a Notice of Availability, an NOA, in the Federal Register. What we are very interested in seeing is that when that document is ready hopefully the NOA is ready at the same time and they can all happen at the same time.

But if they get disconnected we really want you to look for the opportunity say all right, while the federal process catches up we are going to publish our FSA. We are going to move forward towards the workshops that we are going to do normally and basically take advantage of those time lines. Again, making sure things are happening in parallel and not sequentially.

And that is going to require you to be a little more nimble than we typically have had to have been in, you know, combined cycle, two-on-one, gas power plant siting cases with no federal override.

So we will as an industry try to help you understand those things and also ask that you move as fast as you can. There are typically 10 or 14 day notice requirements so you can't move without regard to those things but it will be necessary for you to occasionally decouple the process and reassure your federal counterparts that you are not leaving them behind. There's got to be a train metaphor in here that I've thrown in somewhere along the way but I'll just let that go.

In any event I think that' probably enough on the permitting process. I think there are lots of opportunities to make up time through your process. We are not going to need to intentionally slow down these processes. If we act smart we can make sure we take maximum advantage of the time.

Transmission. I'm just going to touch briefly on a couple of issues. By definition these things are generally remotely located, renewable resources and we all recognize that. We would ask you to use your moral suasion with the folks sitting around the table and other folks to see if we can get those transmission projects moving at a quicker pace.

We are also going to need you to recognize that it is a hybrid market in California. Now I'm on Steven Kelly's stump, I guess. The folks who are the IOUs -- When I try to explain to people what I do for a living, explain the role of the hybrid market -- and I always choke on the word market. It's kind of like the IOUs, they are both consumers of breads and owners of bakeries. It's sort of that kind of analogy that comes to my mind.

On the transmission side I think it is very important that whatever you do as a Commission that you allow applicants to control their own destiny. We have had some discussion about data adequacy and I'm glad to have conversations with you about those issues. At the end of the day an applicant needs to know that they can control their own half of the schedule, if you will, in moving things forward on transmission. We have some thoughts on how that can all go forward from your perspective.

No disrespect to the ISO or any of the public owners. There's a lot of issues those folks are going to have to work out. You don't control those issues. And we need to make sure that the siting process, the permitting process does not get caught up in those issues and that's going to be a difficult thing.

We heard a lot about costs. You know, time is money. And the longer these things take the more trouble we are going to have having projects go forward. And I think this famous cross hatching you were asking about, part of that reflects the time it takes to permit a project in California.

You get to the end of that process and you go through the Commission process, you go through an appeal to the Environmental Appeals Board, you go through litigation and, you know, you are dealing with a project that is five years old or more. So the more time you can shave off the permitting the more likely you are to not have those questions about contracts not going forward.

And finally I guess I want to talk a

little bit about mitigation. Mitigation is not clearly defined in statute or regulation. It's sort of art not science. You know it when you see it. But NEPA and CEQA are definitely -- They'll give you a Chinese menu to pick from. These four things will satisfy your mitigation obligations.

There are some typical suites of options that the Commission has used in the past. You have used things like avoiding impacts, minimizing impacts, buying compensation land. You have set aside lands in the past, you have used conservation easements, you have used mitigation banks. Which applicants actually like that option. Funding trusts for public lands or similar trusts to put together a project's specific mitigation.

We also need to recognize that an acre is not an acre is not an acre. Some habitat has a lot of value. If you have a piece of property that connects two pieces where the critters move back and forth connectivity, as my biologist told me. That's a much more valuable piece of property than just a regular acre of land elsewhere. And you have been very good about recognizing those kind of things.

I bring those issues up because renewable projects, they are land-intensive. There's no way around that. Solar projects in the desert. Some of these other projects are very land-intensive. You know, we're talking about 3,000 to 4,000 acres for a solar project when you probably need 15 to 20 for a natural gas project. So part of the permitting problem is dealing with that whole issue. Figuring out how to deal with those things moving forward.

Your Commission is going to have an opportunity, at least at the staff level, to have a big influence on the outcome of what people are going to ask the industry to do for mitigation. And part of that will occur through the federal biological opinion, the ESA process. It will also occur though between your staff and the Department of Fish and Game staff sitting down with the federal regulatory staff and figuring out what is adequate mitigation.

And again there is no set definition. We are going to have pick among things. You start thinking about lands at one-to-one for a lot of these areas. That's still a lot of land and you may not be able to come up with 3,000 acres of land for mitigation. But maybe you can find 200 somewhere that's really high habitat value and maybe you can fund some endowments.

But all that stuff is very, very much up in the air. And one of the biggest uncertainties that renewable developers are facing right now is how to put a number in that pro forma for mitigation costs.

There is also -- You know, we have talked about what you can and cannot say. We've heard rumblings about people wanting higher mitigation ratios in other similar projects. We think it is important to hold the line and treat power plants like other projects are treated and not create a class of one with power plants on mitigation. Three-to-one, five-to-one mitigation just because they think that might be interesting.

I guess the point is that the renewable projects are going to have to try to shoulder this burden. The ones that are on public land, federal government land. People have actually two obligations to have their mitigation obligation. And at the end of the day they also have a restoration obligation. Those costs also go into the pro forma.

So a lot of this is a long way of saying that you are going to have some significant influence and it is probably going to occur outside of the public process, frankly, about how biological mitigation issues are handled through the state and federal resource agencies. And we really want you to be mindful of the impacts on those projects, both financially and reliability.

You know, dealing with your staff has been basically figuring out how to put together a menu of mitigation that is going to work for these projects as they go forward.

And I think the real quandary that you are going to face is that you need to develop some kind of programmatic approach so you treat similar projects similarly. But at the end of the day you also don't want to kill the ones that are first in the queue as you wait for a programmatic solution.

So good luck with that one. I'm sorry but I think that's where we end up. And I've probably used up all my time so I think I'll stop there.

PRESIDING MEMBER BYRON: Certainly not all your time, Mr. Harris. Thank you very much, excellent comments. You got a lot in there not talking about any specific projects.

MR. HARRIS: Thank you.

PRESIDING MEMBER BYRON: Okay. I feel obliged to offer Mr. Braun an opportunity for public comment if you feel you haven't had an opportunity to voice them. And then I am saving one last card, Anne Gillette from the PUC.

MR. BRAUN: Thank you, Commissioner. Actually very briefly, setting all the issues aside that we look forward to working on.

I think we don't want to lose sight of the fact that as public agencies in California we can be our own lead agency for CEQA for transmission siting purposes. We have a low cost of capital, relatively speaking, to many other market participants.

We have other advantages in siting of infrastructure within our local communities just as a matter of course. So we want to do our part to move forward beneficial projects and I don't want to lose sight of that as well as we are considering these issues of how to make these things work. So thank you very much and I look forward to working with everyone.

PRESIDING MEMBER BYRON: Very good.

Thank you, Mr. Braun.

The last card I have is for the PUC; we saved the best for last. Ms. Gillette.

MS. GILLETTE: Thank you. I realize it's late so you will be very glad to know that I don't have any illustrative cost charts to share with you now.

I just wanted to generally address the issue of coordination. As Suzanne mentioned we do have a 33 percent implementation analysis that the PUC is kicking off next week in a workshop on August 26. We very much look forward to having the CEC literally at the table there as Suzanne is going to participating on behalf of the CEC.

In the comments to a data request that we released in preparation for the workshop several parties commented on the need to collaborate the fact that CEC is doing a study, the ISO is talking about doing a study, we're doing a study. ARB is now looking at 33 percent. And we feel collaboration is very important and will not only keep us from duplicating our efforts but allow us go back to the expertise of all the different agencies.

So along those lines, our comments about which variable should be the focus of the IEPR analysis. Our recommendation would be to focus on some of the later year work that was mentioned in Attachment A. A few things, a few specific things that were listed here. Electrification of the transportation sector, contribution of the POUs, meeting biomass RPS goals.

These sorts of issues and the outer year issues in general are things that we won't be able to look at within our plan since our analysis is really looking at 33 percent in the context of the IOUs LTPPs and that only is going to go out to 2010 or 2020. So we would very much appreciate being able to collaborate with you on the outer year scenarios. And also your expertise in areas like the new technologies you have been already looking at in the workshops in July. Both renewable technologies and renewable enabling technologies like storage.

In general I think we would like to see ways that we can coordinate to -- Understanding we are going to need a lot of new technologies to get to these ambitious goals. How we can align the very valuable work that is done in PIER and TRP with the ERRP program that we have and our procurement transmission prices in general to make that we have a good pipeline from research demonstration to actual commercialization of these technologies in California.

So other than that we wanted to express our appreciation for the mentions of the PUC analysis that are made in this attachment and the efforts that were mentioned here to incorporate that work together. Again, we think that collaboration is very important.

And we heard, for example, at the July 21 workshop from the ISO that they needed build-out scenarios to do their 33 percent analysis. And so we are now working with them on coordinating the PUC's build-out scenarios that we are doing within our 33 percent analysis. Feeding those scenarios to them essentially so they can do their 33 percent would-be scenarios and have a consistent analysis of what we need to get to 33 percent.

So I'm happy to take any questions but those are our general comments.

PRESIDING MEMBER BYRON: We probably could ask you a lot but I think the dais is running weary and maybe others are too. Thank you for being here today.

MS. GILLETTE: Thank you.

PRESIDING MEMBER BYRON: Are there any people that would like to make a public comment before we close?

MS. TEN HOPE: We have staff on the line who is prepared to quickly answer a couple of questions that you asked this morning. Pam Doughman I believe is on the line.

PRESIDING MEMBER BYRON: Okay. Pam, go ahead. Please tell us first what question it is you are going to answer.

MS. DOUGHMAN: Okay. I was able to contact the people who did the E3 study and the Wiser and Bollinger study on natural gas. And so I just have some information to follow up on, some questions that you asked earlier during the presentation by Suzanne Korosec.

Let's see. Regarding the first question of where does PV fall on the E3 supply curves. And also did the study include DG PV only? The study included distributed generation PV only. The cost for PV would be above the other costs if it is understood in terms of the total cost perspectives. However, if you look at the utility cost perspective then it would be -- Cost for distributed generation PV would only include the incentive payment. And that is actually a negative cost by 2020 because the relatively low incentive cost in the outer years is more than made up by the wholesale energy and capacity savings.

The second question was whether the costs in the E3 model were current costs. Yes, the costs were current costs. Nothing in the referent case assumed market transformation, although the model allows the user to do scenarios that change the costs up or down over time.

And then regarding natural gas savings. The model did not include any impact or renewables possibly reducing the cost of natural gas. And it did not include any impact of backup generation for renewables other than possible peakers needed. Just to meet peak demand, not operational impacts of renewables. But the model did include a reduction in the amount of money paid for natural gas fuel because it showed displacement of natural gas generation with renewable generation.

Then I also have some answers regarding the Wiser and Bollinger study. They did not directly account for the fact that with more renewable energy we will need to ramp fossil fuel more often or have more spinning reserves. And these will tend to reduce the magnitude of the gas demand reductions.

But they assume that each megawatt hour of new renewable generation offsets .75 megawatt hours of gas-fired generation at an average heat rate of 7500 BTUs per kilowatt hour. And they noted that this is a conservative assumption, assuming that renewables offset 75 percent natural gas and 25 percent other.

So I hope that helps to clarify some of the questions you had earlier.

PRESIDING MEMBER BYRON: It does, and also raises some others. But I really appreciate that you were able to, in real time, try to provide answers. And you probably had them hours ago and you patiently waited on the phone.

But let's do this, Pam. I'd like to meet with you later since I am the one that asked some of questions. I think in the interest of time here we don't need to go into any more detail. But thank you very much for coming up with those responses. Anyone else?

MS. DOUGHMAN: Thank you.

PRESIDING MEMBER BYRON: Any closing comments from my fellow Commissioners?

COMMISSIONER DOUGLAS: No.

ASSOCIATE MEMBER PFANNENSTIEL: I wouldn't dare.

PRESIDING MEMBER BYRON: I will be quick. Clearly we have discussed a lot of issues. We had a lot of good input today in this Committee Workshop that combines, really summarizes three prior staff workshops. And it definitely indicates how complicated this is and would indicate -- We seem to think that all these things are under our control and that we can fix them all and I sure hope that's the case.

Very little was talked about things like the production tax credit, which is so important to renewables moving forward here certainly, and that's at the federal level. So let's just take that under our control too. At least what we think we can control.

The impact of out-of-state renewables. Working with Western States in cooperation with the renewable transmission initiative. I'm sorry, part of the Western Governors Association. There are so many things that are important here that we have brought up and discussed.

The '08 IEPR will be somewhat limited as an update document in terms of what it addresses on this topic. But I think we have gone a long way in identifying the scope of what we need to do to address this topic in more detail in the '09 IEPR.

I would like to thank the staff for really giving us a rich content workshop here today. And most of all, all the participants for being here and as patient as you have been. Very good input to us.

And I think with that we are adjourned.

(Whereupon, at 5:30 p.m., the Joint Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, RAMONA COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 28th day of August, 2008.