COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                      )
                                       )
Preparation of the 2007 Integrated     ) Docket No.
Energy Policy Report                   ) 06-IEP-1c
                                       )
             and                       )
                                       )
Implementation Renewables Portfolio    )
Standard Legislation (Public Utilities)
Code sections 381, 383.5, 399.11       ) Docket No.
through 399.15, and 445; [SB-1038],    ) 03-RPS-1078
[SB-1078]                              )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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9:32 A.M.

Reported by:
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I N D E X

P R O C E E D I N G S

9:32 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning; I guess we're ready to begin. I'm Commissioner Jackie Pfannenstiel, and this is a workshop on the Integrated Energy Policy Report. Specifically on the subject of the renewable portfolio standard and improvements that we can suggest. There's a lot of material to cover today.

Let me introduce to my right Commissioner John Geesman, who is the Associate Member of the IEPR Committee, and I think as everybody remembers, was the Presiding Commissioner on last year's IEPR Committee, which teed up the update process that we're in at the moment.

And to John's right is his Advisor, Suzanne Korosec. To my left is my Advisor, Tim Tutt. And to Tim's left is Steve St. Marie, who is Advisor to PUC Commissioner John Bohn, who is, in fact, one of our team members on the IEPR Committee; has been working with us. And Steve is here because Commissioner Bohn is not able to be here today, but we are represented by the PUC.

We have a very full agenda. I think people have had a chance to get the materials and the copies of the agenda. We have several panels in the course of the day. So, why don't I turn it over to Bill to give some logistical remarks before we jump into the panels.

MR. KNOX: Thank you, Chair. Good morning, everyone, and welcome. Thank you for coming short and long distances to be here today.

Just a few housekeeping items before we start. For those of you who are not already familiar with this building, the closest restrooms are located right over here, out the door and to the left. There's a snack bar on the second floor under the white awning.

And lastly, in case of an emergency, and if the building were to be evacuated, please follow employees from the building to the appropriate exits. We would then reconvene in Roosevelt Park which is located diagonally across the street there, just to make sure everybody's out okay. If evacuation should be necessary, please proceed calmly and quickly, again following the employees of the Commission here. Of course, we don't expect any kind of evacuation to be necessary, but this is something that we read at every meeting.

I think we're about ready to move into the first of three panels. The structure of today's workshop includes three subject areas. And in each case there'll be a set of presentations followed by a roundtable discussion by the panelists. And then time for public comment.

The first set of presentations and panel will be looking at benchmarking time of delivery factors and what are the effects of time of delivery factors in terms of evaluating bids and SEP payments that might be calculated for various bids into the RPS program.

The second panel and discussion will be talking about ways that bilateral contracts might be streamlined in order to achieve the longer term goal of 33 percent renewables by 2020. And we'll also be looking at ways to prevent delay or failure of contracts, of RPS contracts. And that panel and discussion will be after our lunch break.

Following that we'll have another short break, and then the third and last session will be discussing transmission-related issues, particularly interconnection queue policies and cost allocation. And then also the transmission ranking cost reports and how they're used in bid evaluation.

So at this point what we'd like to do is to start with the first panel. And the three speakers are Rich McCann of M.Cubed, who's going to talk about natural gas price forecasts and compare them.

And then Snuller Price from E3 Consulting talking about a comparison of TOD factors used by the utilities in RPS, and comparing them with some other similar factors.

And then Tony Goncalves of the Energy Commission Staff here who has a presentation about the potential to game SEP payments by adjusting generation profiles in response to TOD factors.

So, with that, I'll get things set up for Rich to start off with a comparison of natural gas price forecasts.

DR. McCANN: Thank you, Bill. Good morning, thank you for inviting me to come and speak before you about this. I'm going to speak today about the natural gas price forecasts that have been prepared and reviewed in various contexts in California, nationally and across the west. And also talk some about the purposes of those.

And so I want to go through my, introduce what I'm going to talk about. I've forgotten which button it is. Which one is it, oh, there it is. Never do enough PowerPoints, always get confused.

So I want to first talk about how forecasts are used. And there's actually a lot of ambiguity out there about why forecasts are prepared and what their specific uses are. And I'm going to talk a little bit about that.

And then I'm going to go into reviewing some of the forecasts that have been prepared, both at the national level, working down to California and some specific contexts in which forecasts are prepared, and in particular looking at the MPR forecasts. But in looking at that compared to other forecasts used at the PUC.

And then finally discussing somewhat the issue of how many of the forecasts that are prepared and used at the PUC are basically unavailable for public scrutiny. That they are available on a confidential basis among different parties, but there's not an ability to basically compare them across proceedings.

So the first question is why do we use forecasts. There's actually two reasons why we use forecasts, and very often policymakers and even analysts don't understand why forecasts are prepared.

The two contexts are for planning, which is basically for assessing your options in terms of decisions that you might be making. And the second is for contracting, and that's for setting specific prices and terms in contracts; even in ratemaking. Ratemaking is a form of contracts.

For planning what you want to basically be looking at is a range of forecasts, so that you can look at the types of uncertainty that's involved. You're not focused just on an expected value. You're expected on the variance or the volatility of the commodity that you're looking at and trying to determine what kind of prices are involved, what kind of other factors that are coming in might affect your future outcomes.

And then looking at how do you plan for those possible changes from the expected outcome that you're looking at.

For contracting you're much more likely to have a point forecast. That is a single line that's drawn out into the future. And what you do with that is then you make a risk assignment between parties as to who will bear the risk for the forecast being wrong one direction or the other.

The deadband around forecasts is one way of dealing with risk assignment. And one of the things that we fail to do often is to consider the fact of how we're going to use the forecast that we're preparing. And once we have that forecast prepared, what do we do with it. And keeping these two distinctions is really quite important in looking at any forecast.

Now, the CEC is primarily a planning agency, so the type of forecasts they're going to be dealing with are mostly planning forecasts. Ones that have ranges around them looking at possible outcomes in the future; trying to figure out how to balance one decision against another.

The PUC, on the other hand, is almost entirely contracting and ratemaking. The PUC has to deal with point forecasts; has to make risk assignments between parties as to who will bear the risk given deviations from that forecast. And it's all involved, all of this ratemaking process is entirely works around the same sort of point forecast in the future. In terms of setting rates, that's a contract between ratepayers and the utilities.

And so it's important to keep that in context while I'm talking about these forecasts that I'm going to discuss as we go along.

Now, the other thing is that there is uncertainty in forecasts. I will say that every forecast will be wrong. Just take that on the face of it. You know that the price of gas will not be $10 in the year 2020. If it happens it will be purely coincidental.

And so what we have to do is we have to ask the question, what are the consequences of being wrong. And that's where you use this forecast in order to make those kinds of assessments.

You can have, with the CEC you're going to be doing a range of forecasts. At the PUC you have to decide who's going to suffer the consequences or gain the rewards of the forecast being right or wrong.

And one of the things that you want to consider when you're looking at this question of how uncertain a forecast is, is what are the financial consequences, the economic consequences of the forecast being off one direction or the other.

And actually it's very dependent on the discount rate. What you're going to be doing with discounting is that you're basically saying a dollar tomorrow is not worth as much as a dollar today. And there's various ways of doing discounting. But one of the consequences is that the value of something out ten years from now is quite a bit less than the value today.

And what you find is that in the first 20 years of a 40-year time horizon that most of the value of your forecast is incorporated in that first 10 to 20 years. You don't really -- the next 20 years really don't matter that much.

It also depends on what your discount rate is, and on what the underlying real escalation rate is in the price.

And so, for example, if you have a 2 percent escalation rate in the underlying price above and beyond inflation, that the next 20 years, from 20 to 40 years, is actually still fairly important; just not as important as the first 20 years. But if you have no real escalation rate, almost all of the value is compacted into the first 20 years of the time horizon that you're looking at.

And so I've prepared a couple of graphics to show how this distribution is over a time period. You can see that this front row is using a 5 percent discount rate. This is a nominal discount rate. This is a kind of a discount rate that you would use for a real -- for doing a social impact analysis, is a very common social discount rate of 5 percent.

And this is with a zero percent escalation rate. And you can see that in the first 20 years about 63 percent of the value is in the first 20 years.

If you go to a 10 percent discount rate, which is actually quite close to the rate that is used for utility ratemaking and for the MPR and some of these other contracts, that 80 percent of the value is in the first 20 years of the time horizon that you're looking at. And you can actually see the impact in the first ten years is more than twice what it is in the second ten years. So the first ten years has most of the value compacted into it with discounting.

Then we can also look at a case where we have a 2 percent real escalation rate, and you can see that it flattens out some, especially with the 5 percent discount rate. We can see that approximately 55 percent of the value is in the first 20 years here.

And then with a 10 percent discount rate, it's still, most of the value, again, is in the first 20 years of the contract of this 40-year time horizon.

So this is important to keep in mind of where you focus on in terms of trying to get some accuracy or concerns about uncertainty in your forecast. You're not concerned about uncertainty to a large degree this far out into the future. Being wrong is not going to have a big impact on your near-term bottomline. And that's an important point to keep in mind while we're looking at these forecasts.

So, I'm one step into looking at some of these forecast reviews, or reviewing the forecasts that we've looked at. I'm going to go through the NYMEX futures, some national forecasts, forecasts out of the Pacific Northwest, a neighboring region, the CEC's own forecasts, the PUC's forecasts that were prepared for both the MPR and the avoided cost analysis, the publicly available IOU forecasts, which is not all IOU forecasts. And then finally looking at the California ISO forecast used in their transmission studies.

This is a graphic I just pulled off a website for the NYMEX gas futures. And you can see that this is the closest month on each of these closing days. And you can see how the NYMEX future price over the last year basically rose to about $15 mBtu, and then fell down to where it's now around $6.50 per mBtu.

And you can see that there's quite a substantial swing over the year in the NYMEX future prices. And that swing is reflected in the changes over time.

What you can also see is the monthly pattern that is built into the NYMEX futures prices. The dark blue line is the futures from June 7th of this year. And this is out to the year 2011, by month. You can see that it peaks during the wintertime, falls during the spring, goes back up during the summer, and then peaks again.

You can see that the futures prices went up in the two months from June to August. There's an expectation that gas prices will be higher in the winter than last June. So you can see that monthly pattern, and that actually will play into your TOD profiles, as well.

And then we can also look at the NYMEX futures compared to the CEC draft forecast that was prepared in June. And you can see that the NYMEX futures prices are running along this line from 2007 to 2011. The futures prices last December were much higher; then they fell in June; and then they went back up again in August. And they are above the CEC draft forecast at this point, but they converge in 2011.

Moving on to looking at the national gas price forecasts, what we have here is the NYMEX futures prices from the previous slide from December of 2005. And I picked December 2005 because that's also the month in which the Energy Information Administration prepared their annual energy outlook forecast. So, in some ways these should be comparable in terms of how they're looking at the future.

And then I also have the CEC's draft forecast prepared in June. And you can see that the EIA forecast runs below these other forecasts. And it was prepared, like I said, in December of this year. And it runs out over a long term. It's a fundamentals forecast that uses a sophisticated model, looking at various purchases and resources that are available around North America. And this particular forecast is widely used in various forums.

Then we can move on to looking at the Pacific Northwest. Again, I put the CEC forecast here for comparison purposes. The Northwest Power Planning Council prepares three different forecasts. And this forecast was actually prepared in April of 2002. And they used it in the fifth power plan was which released in 2003.

Talking to the Power Planning Council's Staff a couple months ago, they said that they were not really prepared to update their forecasts; that they were relying on their high-end forecast, which is this, the green triangles right here, in doing their analysis. And so that's their case right now, is using this range again for planning purposes going forward.

The California Power Administration just recently concluded a ratecase, their 2007 ratecase. This is their price forecast that they use. It was built off of the December 2004 Energy Information Administration forecast. And, again, it's a fundamentals forecast.

And then there's the PacifiCorp, which I'm going to come back to them later, as well. But they prepared a gas price forecast that they use both at the Oregon Public Utilities Commission and at the California Public Utilities Commission. They prepared that in November of 2005.

And you can see how that forecast is riding along the upper edges of the Power Planning Council forecast. Again, you can see that there is quite a range among the forecasts, even in that region.

Then this is a look at the CEC Staff forecast that had been prepared over the last five years. This light blue line, or turquoise line, is the 2001 staff forecast that was used for the IEPR analysis. The orange line is the 2005 staff forecast, and I'm going to come back to referencing that because that forecast gets pulled into some other proceedings. And then finally here's the staff draft forecast that was prepared in June for the next round of the IEPR.

Moving on we can look at the PUC forecast. And this is where we get to the forecasts that are really relevant to the RPS. What we have here is, again here's the CEC 2005 forecast that I showed on the previous page.

Then there is the green line, which is the 2005 MPR forecast that was adopted last April by the PUC. And that was, the first part of this forecast is based on NYMEX futures; then there's a transition period that goes to a fundamentals forecast, which is a mix of three different forecasts, two private forecasts and the CEC.

And then there is the PUC's avoided cost forecast, which was prepared for evaluating energy efficiency and some other proposals. These two forecasts were prepared in separate proceedings, but the proceedings had some cross-over between them. They had a lot of parties involved in both of those proceedings at the same time, actually three proceedings. The R04-04-026, which is the MPR forecast. And then this one was prepared in the R04-04-003 and R04-04-025. Lots of numbers there.

So what's interesting about this is they don't overlie each other. They overlie each other a little bit after about 2014, but they still are not right on top of each other. And yet these two forecasts were adopted less than two weeks apart at the PUC.

You can also see that the NYMEX futures prices were a little bit above this in December, although that may reflect -- I think this reflects the fact that there's an averaging of 60 days of NYMEX futures in that time period. So it will be a little bit different.

But this is occurring at the PUC, two public forecasts with different results. And they actually -- the other important thing is to go back to my point about uncertainty, and the importance of uncertainty. The largest difference between these two forecasts is, in fact, in this time period which is of the greatest consequence, the first ten years. They're similar in the second ten years, but that has less of a consequence. This difference here is more important.

Now, the other thing is to look at the forecasts that are presented at the PUC by the various utilities. And one of the problems is actually getting publicly available forecasts. Various parties are limited in how they can release the forecast.

The two publicly available forecasts that I was able to pull out was the one for PG&E's ERRA, which is this forecast here, that was released in October of 2005. And PacifiCorp's forecast for its GRC that was put out in November of 2005.

And you can see that there's actually, these two utilities have very different expectations about the future gas prices. And the PUC is making decisions based on these very different expectations about future gas prices.

In reference, because these were prepared last fall, the reference forecasts would be the PUC's MPR forecast from the previous year, the 2004 MPR, which was finalized in February of 2005. And you can see how that forecast basically cuts through the middle of these other forecasts.

And then there was the PUC's avoided cost forecast, which was prepared in April of

2004, which also runs along between those forecasts.

So the other set of forecasts which have an influence on the RPS are the ones that are used by the California ISO in doing their transmission studies. We looked at two studies, one for the Palo Verde-Devers 2 line, and another one for the Sunrise Power link.

The Palo Verde-Devers line basically used these two points; they use single-point one-year forecasts in order to do their analysis, 2008 and 2013. And they didn't really look at consequences over time in doing their analysis. They were very much focused on single years, in large part due to the complexity of the transmission studies. But it's also they're not necessarily looking out at the consequences over the future.

And then there's also the forecast here for the Sunrise Power link, which was done over a year later. And their forecast they actually drew from the SSGWI, which is the Seam (phonetic) Steering Group for the Western Interconnect, which is one of the many acronyms in the western interconnect that are doing various transmission and planning studies.

So, with that, I want to move on from looking at the forecasts that have been used, and look at what are the availability of forecasts. And we went back through a number of the proceedings at the PUC and tried to pull out the forecasts that were available. I haven't shown all of them because some of the forecasts are obsolete by now.

And I don't expect you to be able to read this chart. It just basically is a list of the proceedings. This is for the proceedings in 2003 and 2004. And the notations in blue, those are the ones that are actually the most important, because those are places where we found that we could not get the forecast because they were being held confidential for one reason or another.

So that the CEC is not in a position right now to be able to review these forecasts that are prepared by the PUC. And there is no one who is actually reconciling these forecasts, that we're aware of that are reconciling these forecasts across proceedings. So that there are a number of cases where one forecast might be used in one proceeding, and a different forecast used in another proceeding. And it's not evident that there is some reconciliation process going on.

You can see that when we move into 2005 there are many more blue notations. The forecasts were more publicly available in 2003 and 2004. And they're becoming increasingly difficult to acquire for public review.

And so that's one of the consequences of what we were doing in preparing this analysis, is that we were not able to really pull together a number of forecasts that we could compare with each other.

And with that, I believe I conclude. Yes. Thank you.

MR. KNOX: Our next speaker is Snuller Price from E3 Consulting. And he's going to be talking about a comparison of TOD factors and similar time-varying factors used in electricity procurement.

MR. PRICE: Thanks, Bill. Good morning, everybody. I'm going to walk through a few slides to basically explain the time-of-delivery factors. I know there's been a lot of questions, a lot of, at least we feel, a number of questions about how they work, where do they come from and so on.

Hopefully by the end of the next 20 minutes everybody will understand why we have time-of-delivery factors, where they came from, how they compare to similar factors that are being used. And then that should lead us into the panel discussion later.

The overview is pretty much that. I want to try to give, you know, why we have them and what they do. And look at some and talk about what their implications are.

The time-of-delivery factors were introduced in a market price referent proceeding at the CPUC, which is required by the RPS legislation to establish appropriate market price referent.

In the 2004 MPR proceeding there were really two MPRs that were developed. One is a baseload MPR, based on a combined cycle gas turbine; and another one was a peaker MPR based on a CT, the all-in costs of a CCTT and a CT.

And in the 2004 proceeding it was felt that those two choices didn't necessarily fit the output profile of all the different types of renewable resources in the state. So the time-of-delivery approach was introduced in 2005 to basically put different generator output profiles on a comparable basis. And I'll talk through how the TOD factors work, but the idea is to be able to compute a custom market price referent for different output shapes.

So the TOD factor methodology overview. One of the questions that we're going to be addressing, I think, in the panel later is how are the time-of-delivery factors computed. Because obviously they influence what that custom MPR is for each resource.

Each of the investor-owned utilities develops their own time-of-delivery factor in their proceeding, and then submit those to the CPUC.

There is a summary description of how the time-of-delivery factors are created that has been filed, and are sort of paraphrased in this bulleted list here at the bottom.

Mostly the time-of-delivery factors are based on a forecast of future energy prices. So it's intended to be sort of a market-based component, either NYMEX, broker quotes, or third-party forecasts of energy prices. Those are generally publicly available information.

Then they are translated to hourly prices. And that is proprietary. I don't know exactly how each of the investor-owned utilities has done that, but they've taken forward market data and translated to hourly prices; and then averaged over time-of-delivery periods. That's the energy piece.

The time-of-delivery factors also include capacity. The capacity value, itself, is developed, and I don't know exactly, but Southern California Edison has an option analysis; and they also have production simulation model that calculates loss of load probabilities. The capacity costs are allocated to hours based on LOLP allocation.

PG&E has a different methodology, but similar. Estimating a value of capacity and allocating it to hours.

Once you've got this sort of combined energy and capacity shape, then they're normalized, okay. So the time-of-delivery factors, if you have a baseload plant that runs just 24/7/365, the time-of-delivery factors will come out to be a factor of 1. And we'll take a look at those in a minute.

Question, I know I went really quickly through those methodologies. I wanted to show a picture of what comes out of those processes. And here I will say, just in the interests of sort of common labeling, I've broken down the time-of-delivery factors, but the name that we've used is a little bit paraphrased from each of the utilities.

And I also will say that there are differences between the time-of-delivery period definitions that explain some of the differences that we're seeing here, but not a lot. For example, I believe Southern California Edison's highest summer period is six hours, and PG&E is eight hours, which will explain a little bit of the difference.

And I have the definitions, I think, in the back of the presentation, but I didn't want to go through all of that in 20 minutes.

The Southern California Edison number, I think we've got a number of questions on this. How did this get high? And I think the answer is allocation of capacity costs, but, you know, we're not exactly sure because we haven't seen all the breakdown.

And here, by the way, is 1.0. I'm not sure if people can see the cursor, but the 1.0 would be, by definition, average. The summer onpeak for Edison is at about 3.2. About 1.9 for PG&E. 1.6 for San Diego Gas and Electric and so on.

Now, the other question has been raised, well, okay, there's a proprietary process. We create time-of-delivery factors. How do we know these are the right way to compare output profiles.

And there has been -- the CPUC requested that each of the utilities file benchmarking proposals. And I've summarized here, as best I could, each utility's proposal for how to do some benchmarking. In just a minute we're going to do some other comparisons, as well, of these profiles to other sources.

All of the benchmarking proposals pretty much use, you know, nonproprietary, either forward broker quotes, NYMEX data, that type of thing. And then allocated in different ways.

I think the reaction to the benchmarking proposals was that benchmarking is a good thing, but I don't think there was one strong benchmarking proposal adopted by the CPUC. I think it's an area they're still working on and looking at, trying to figure out how to do benchmarking.

The other thing we wanted to do was to compare the time-of-delivery profiles to some other sources. The first one we thought of was the qualifying facility SRAC formulas, because those are similarly used in procurement. And they provide a similar weighting of value by time-of-delivery.

So we've created a set of comparable QF time-of-delivery factors. This is a quick summary of how we did that. The only trick is that in order to get the capacity piece of the QF you have to assume an energy price. So we did, we used $80 a megawatt hour. The number there that you use, as long as it's within the range, doesn't really change the results much. Then, of course, we normalize at the end so that we get this sort of average of 1.

I'm just going to walk through each of the utilities' comparison of the time-of-delivery factors we've mentioned so far. There was the -- we were going to look for each utility of the 2006 time-of-delivery factors, so those are the most recent in the RPS RFOs that have just gone out.

The 2005 time-of-delivery factors which were used in the last solicitation cycle, and then the QF factors.

What I've got here along the horizontal axis is the 8760 hours per year. And, again, the time-of-delivery factor with 1.0 right here. The reason why they're blocky is because each hour within a particular time period has the same value. So, as you sort them across, they kind of block down, okay.

This is Edison's. We saw the 3.2 number here in the summer peak. And then it steps down and each subsequent time-of-delivery factor period.

Comparison to the 2005, the 2005 TODs, I believe in the 2005 solicitation cycle Southern California Edison just used the QF factor. So I think that they should be, if not exactly the same, very similar. Maybe that $80 megawatt hour that we're seeing a difference there, but those are the same for all intents and purposes.

PG&E time-of-delivery factors. Again, a little bit broader summer peak period. Here's the

2006 cycle; it's up at about 1.9. The QF is, what, 1.6, something like that, the summer peak. And then in the most of, a lot of the hours of the year they sort of tend to bounce around the same numbers.

San Diego Gas and Electric. Here we go, we've got the 2005 and 2006 are the same; and the QF factor here is a little bit flatter.

The other thing we did besides comparing the time-of-delivery factors to the QF factors is to look at other nonproprietary sources. We took two that are similar to those that Rich used for the natural gas forecast.

We looked at the California Energy Commission building codes. So these would be the time-dependent values. And those are the set of avoided costs that are used to look at the cost effectiveness of proposed building code upgrades. Those are developed with completely nonproprietary data in the building codes process.

CPUC avoided costs. Richard also mentioned those. Those are from the CPUC phase one avoided costs. The first difference you'll notice is that both the CEC building codes and the CPUC avoided costs are hourly, so they have a smooth trend.

And with those two factors -- oh, and again we've normalized, so we've taken away the energy price value and again here's the 1.0 number.

What you see is both the building code TDVs and the avoided costs are the highest hour is actually higher. I think we truncated the chart. It goes up pretty high in the very very few top hours. And it goes lower at the very bottom hours. And they're pretty similar along most of the year. Okay.

So, what that will do, of course, is if you have a renewable generator with output that has most all of its output in the very highest hours, you'll get a bigger difference. If you have a renewable generator with most of its output in the very low hours, you'll get a bigger difference. And the rest of the hours it's going to be pretty comparable.

I know I'm kind of going through this pretty quickly and I'm going to try to slow down to do a little bit of math. We've been asked many times how doe this work, how does this work. What we wanted to do was two examples.

One was based on a solar output shape. We used a photovoltaic shape and a baseload shape. I'm actually going to skip ahead and do the baseload shape first, because it's the easiest. And then we'll come back and look at the solar.

What we've tried to do is for each utility, Southern California Edison, PG&E, San Diego Gas and Electric, do comparable bids. So, the same contract price. And look at how those bids would flow through the different RFO processes at each utility and what's the difference.

Two calculations. First, there's calculations in rows 1, 2, 3 of the sort of custom MPR that we talked about. Then there's the calculation in rows 4, 5 and 6 of what we're calling here the final bid price. Some of the terminology has moved around. This has also been called the levelized final contract price. That is the average price that the generator actually gets paid.

So, how do you calculate this custom MPR. You take the baseload MPR, which is again based on the all-in costs of a CCGT; you multiply by the annual average TOD factor. Okay, so that is the average factor in the hours that your output profile that you're generating; and you multiply those two and you get your adjusted TOD MPR.

Now, because this is a baseload example, the average TOD factor is 1.0. It's 1.0 despite the differences in the TOD factors for each utility. And so the MPR is unadjusted, the levelized TOD MPR is the same for each utility in this case, baseload case.

The second calculation is the calculation of the final contract price. Here we've got each bidder bidding $95 a megawatt hour. Again, the same average TOD factor is 1. Multiply across. So we end up in each case a final contract price of $95, MPR of 79.14.

So now the question is, all right, what piece of this does the utility pay in their procurement, and what part of this bid gets applied for in SEP payments.

So the MPR is -- the adjustment MPR is 79.14 in each case, so the utility pays the 79.14. And then the difference is $15.86 per megawatt hour in each case, and that would be the SEP payment.

All right, pretty simple if we're doing the baseload. All the factors are 1.

I'm going to roll back to the solar example and do the same thing. So, again, the contract price for each of these is going to be $95. The baseload MPR is unchanged, too, $79.14 in each utility. And we took, this was the MPR for I think in the 2005 solicitation example, for 20 years bid, and starting in 2006.

With the solar shape what you find is you get a lot of output in that high summer peak period. And so the average TOD factor for Southern California Edison was 1.24. Remember they had the highest on summer onpeak. PG&E I get 1.12, and San Diego Gas and Electric 1.10.

So now the custom MPR, I'm calling it, or the levelized TOD MPR is the baseload times this factor we just described. And then you start to see some differences. Okay.

So, Southern California Edison's MPR for the solar output shape is $97.76; PG&E's 88.71; and San Diego Gas and Electric 87.02.

All right. Now, second piece of the equation is what's the final contract price, or the final bid price. And what we've done is try to structure the examples so that they're comparable, so that the generator in each utility's case would get, the total payment would be the same, okay, the $95.

What that means is that what the unadjusted bid price would be for each utility is different; it's 76.90, 84.75 and 86.40 when you multiply by the average TOD factor, then you get up to this final bid price. Okay, so this is adjusted.

So, the way I got there obviously is I backed into it. But the important thing is what you -- the sum of your total payments at the end of the day, okay. I don't know if everybody followed through that. So each bidder is going to end up with $95, but we end up with different MPRs.

All right, now let's go look at how much the utility pays, and how much would be applied for in SEP payments. So, in the Southern California Edison case the $95 contract price is less than the MPR. Okay, so they don't need any SEP payments. So that's a zero.

In PG&E's case, the difference is $6.29. And San Diego's case the difference is $7.98.

Okay. So what you start to see is differences based on the time-of-delivery factors in terms of the allocation of how much is coming out of the utility procurement and how much is in SEP payments. And the total of the SEP payment and the utility payments are the same in each case.

I know that was a lot of words and math. So a couple conclusions, and I think we're going to have time for questions of the panel later.

The time-of-delivery factors do change the level of SEP payments, okay, and utility payments. So the sharing between the utility and the SEP changes based on the time-of-delivery factors for resources that aren't, you know, flat. If your flat output profile time-of-delivery factors, as we saw in the baseload case, completely wash out and it doesn't affect it. But for things like solar, it does make a difference.

Now, the other question is well, and I tried to allude to it a little bit in the benchmarking, how do we know whether it's methodology differences that are driving these different time-of-delivery factors. How do we know whether it's something to do with the utility circumstances, maybe they're short onpeak. How do we know that we've got the right factors to be computing the MPR.

And it's difficult to know, okay, given the information that we have, exactly, you know, what's driving the differences, whether they're methodology or situation based.

So that was the quick run-through. Hopefully I didn't take too much time. And I'm going to bring Bill back to introduce the next speaker.

ASSOCIATE MEMBER GEESMAN: Snuller, before you go, the TOD factor stays constant throughout the life of the contract?

MR. PRICE: That's correct.

ASSOCIATE MEMBER GEESMAN: But wouldn't it be influenced by the utility's supply portfolio? Is that changed over time?

MR. PRICE: Yeah, so the question is, right, would you have an opportunity to update the time-of-delivery factors. Certainly the utility portfolio will change over time, but my understanding of the solicitation is that there's one set of time-of-delivery factors for the whole contract period.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. KNOX: Thank you, Snuller. Next presenter is Tony Goncalves, Energy Commission Staff. And he'll be continuing to talk about TOD factors and particularly the potential to game SEP payments by adjusting generation profiles that are used to calculate SEP payments, among other things, using each utility's TOD factors.

MR. GONCALVES: Thank you, Bill; Commissioners. I'm going to cover sort of an analysis that we've done here a little time back regarding the potential gaming of the SEP payments by adjusting the generation profiles.

And what I'll start off with is a sort of a little overview of the process; kind of go into our SEP worksheet that we've put together that we use to calculate the levelized bid prices and MPR; and then go into some of the assumptions and results from the analysis.

I think Snuller may have covered some of this. I'll quickly go through this. But, basically the process is that after the PUC calculates the MPR, the CEC will then use the spreadsheets and that average sort of MPR that's been non-TOD adjusted, and we will put that into our spreadsheets along with the bid price information for generators; calculate a TOD-adjusted MPR which is also adjusted for generation profiles; and a TOD-adjusted and generation-adjusted final bid price. And then, of course, the difference between those two is the SEP value if the MPR is lower than the bid price.

I think Snuller covered most of the TOD information so I don't think I need to really go over a lot of this, but so the MPR is adopted by the PUC as a generic baseload facility. The values are then adjusted by us in our calculations for both the TOD and the generation profiles which results in contract-specific MPRs.

I'll now sort of cover the worksheet and then we'll kind of go into the meat of the presentation which is sort of the results and the assumptions.

The worksheet is used to calculate both the levelized final bid price, along with a levelized contract-specific MPR. And then, of course, the SEP payments, or the SEP value, which is the difference between those two.

This is the worksheet and I'll cover a lot of these pages and the assumptions fairly quickly. For those of you that haven't seen this, I'll cover some of these inputs a little bit later. But everything here in yellow is an input. There's a number of sort of specific information at the top. We do ask for specific TOD factors for the specific utility, estimated annual sales by TOD period; and then also annual final bid price by TOD period.

You'll notice that the terms have been changed. They haven't been changed in the final versions, but we have some agreement to change the terminology to better reflect what they're supposed to represent.

This is the output page from the spreadsheet. And what we end up after going through all the calculations is a levelized initial bid price. And the initial bid price is essentially the price that the generators bid in to the utility under the solicitation.

A levelized final bid price and that represents the final price that was agreed to between the utility and the generator, including any above-market payments.

The levelized above-market cost, which is the SEP value on a cent-per-kilowatt-hour basis. The total amount of the above-market cost, which is basically what the total SEP award would be from the Commission. And then also a levelized TOD-adjusted MPR.

I think Snuller had a graph of the TOD factors, so I'll just kind of skip on over these. And then I'll start in on the assumptions.

I think I have an error here; I think the solicitation year would be the 2004 solicitation year. And even though TODs weren't really used for 2004, we'll just kind of ignore that for this analysis.

Assumed a start year of 2010. Contract term of 15 years. The MPR, based on the, I believe this is correct, for the 2004 solicitation for 2010 was 6.28 cents per kilowatt hour. And even though we're using TOD factors for different years for different utilities, kind of for consistency we use the same value. And then the weighted average cost of capital, which is utility-specific, for this analysis we use the same value once again for consistency.

Now, the scenarios that I conducted were only for the SDG&E's TOD factors and for SCE's 2005 and 2006. Didn't do an analysis on PG&E's. The main reason, as we go back here, is that PG&E

has nine TOD periods, and it was easier for comparison purposes to just use SDG&E and SCE's, although PG&E's would follow along the same lines as the rest of the analysis.

Now just continue here with the assumptions, and we'll start with SDG&E, and I'll quickly skip over the others. What I started with was an average bid price. And we can see here along here for the first ten years was 7 cents; last five years was 6 cents.

And I used that same average bid price for all scenarios. What I did for, actually come up with individual TOD period bid prices was to take the average bid price and multiply those by the TOD factors for the corresponding TOD period.

As you can see for San Diego's here, fairly narrow band from 5.5 to 11.4. SCE's 2005 an even narrower band. And then SCE's 2006, as Snuller pointed out earlier, with the higher onpeak, summer onpeak, you have a much higher onpeak value.

Now, the generation profiles, and I have -- we did nine different scenarios for each of the three TOD options. And so there's a total of 27 scenarios. I'm going to cover some of the generation profiles, although I won't show you all of them. But skip over them.

This is probably one that's more closely representative of a baseline facility with a majority of the hours being in sort of the offpeak hours. This has a majority of the generation, as you can see here, on the winter offpeak; less on the onpeak.

Scenario number two basically is the complete opposite of the previous one where I swapped the summer onpeak with the winter offpeak. And so the majority of the generation now falls in the summer onpeak period.

And this is the last one I'll show you, which is representative of the remaining ones. Although this is not a realistic scenario, for purposes of comparison six of the scenarios took the entire generation for the year and placed it in one TOD period. Here, the one illustrates sort of all the generation in the onpeak, summer onpeak. The other scenarios move it over to the semipeak and so forth.

And then the final scenario is one where there are no TOD factors, or a TOD of 1 for all periods.

And these are the results. Show you this one quickly; I'll move on to the next slide and then come back to this one. Make it a little easier to kind of show how this all worked out by looking at just one of the utilities, which was San Diego's. But kind of just a quick overview.

You can see that changing the different TOD factors and changing the generation profiles can significantly change the SEP value and the total SEP payments.

So for illustrative purposes I'll go through San Diego's. And start here in order where we've got here the SEP value is the lowest. And that occurs when 100 percent of the generation is in the winter offpeak. It was -- for the analysis it was intuitive that as the generation profiles were changed, that the levelized final bid price and the levelized adjusted MPR would also fluctuate up and down.

However, it wasn't intuitive that that difference between the two would change. As you can see here, sort of we have the low with the winter offpeak. As we move to higher generation, or TOD factors, the levelized bid price increases, as does the levelized MPR. However, the difference between those two also increases, which also results in a higher total SEP payment.

Kind of going back, clearly see here that although many of these profiles are rather exaggerated that shifting generation from one profile to another can result in different SEP payments, and different total payments, given that the CEC will calculate the SEPs upfront. Currently doesn't have a provision to go back and revisit. That this could result in higher payments than are really due to a facility; although it could also result in lower payments.

I think the values or the generation that was used in the assumptions, the 199 million kilowatt hours for a baseload plant probably represents about a 25 to 30 megawatt plant.

Given some of the profiles that I have in there, for example, the Edison 2006, which has all the generation in the summer peak, given that that is a very short timeframe, six hours, or I think it's about six hours a day, that's a very short timeframe.

If we were to come up with a representative plant that would generate that amount of generation during just those hours it would be a considerably larger facility than a 25 to 30 megawatt facility.

And with that I'll kind of move forward. This is essentially my conclusion here, which is sort of a tabular representation of the graph. Looking at the two yellow ones in particular, this one a spread with majority offpeak, which is most representative of a typical baseline plant.

When you compare that value with sort of the no TOD, which, as you would expect, given Snuller's presentation, where no TOD factor would be about 1 for all of them, the values come out to be fairly similar in these cases.

But as you look forward, and especially if you look at SCE's using their 2006 TOD factors, the values could vary significantly between about $10 million to $50 million for the total SEP award. While again reiterating that that 50 million value there is probably not a realistic profile, it does show that given that SCE TOD factors, if someone was to weight generation towards the higher TOD factors, it could affect those values.

I would expect that the IOUs would be interested in closely take a look at the generation profiles given that the MPR also fluctuates based on the generation profile and the levelized MPR value is the value that the IOUs will be paying the facilities. Although they actually will make payments based on actual generation. And so these numbers may not be as significant to them at that point.

And with that, I will conclude my presentation.

MR. KNOX: And we're on schedule. Thank you, Tony. We'll go ahead and move to the panel discussion. And this one's moderated by Snuller Price.

MR. PRICE: Okay. Can everybody hear me okay? Fantastic. What I thought we would do for the roundtable with the Chair and Commissioner's agreement, was to introduce the panelists briefly; and then I wanted to address or bring up from the workshop statement some of the questions. And then I thought we could go around the panel and everybody could kind of give their organization's perspective on what those questions are. If that makes sense.

I'm just going to go down the order that the panelists are listed in the agenda. We have, do people want to introduce themselves or should I just pull out a hat. Well, why don't you introduce yourselves.

MR. DOUGLAS: Paul Douglas, I work for the California Public Utilities Commission; specifically I'm Project Manager for the RPS program.

MR. GONCALVES: Hi; I'm Tony Goncalves with the California Energy Commission; and I am the Supervisor in the Renewable Energy Program; and before that for many years I was a Lead for the Existing Renewable Facilities Program.

MR. McGUIRE: Guess I'm next in order. I'm Patrick McGuire; I work with CrossBorder Energy and we represent CalWEA and CBE; it's the California Wind Energy Association and the Biomass Energy Association.

MR. KELLY: Steve Kelly with the Independent Energy Producers Association.

MR. MORRIS: Hi, I'm Greg Morris with the Green Power Institute.

MR. KUGA: Roy Kuga with Pacific Gas and Electric.

MR. BARKER: Dave Barker with San Diego Gas and Electric.

MR. HEMPHILL: I'm Stu Hemphill from Southern California Edison.

MR. PRICE: Excellent. And what I thought I would do, both to get it into the record for the reporter, and also just get everybody in the room up to speed, was just read through the questions in the workshop statement. I think then we'll go around and do some brief remarks.

I guess I probably should repeat that it's important to use the microphone just so that we get folks listening online and the reporter.

So, the questions here, the first one. Do current TOD practices dissuade potential bidders or add unnecessary complexity to the bid process? So increasing complexity unnecessarily.

How big of an impact do TOD factors have on RPS bid evaluations from your perspective?

How/why are TOD factors in RPS solicitations different from the following: time-dependent valuation which I showed as labeled building code in the earlier presentation; methods used to calculate the short-run avoided costs for QFs; and bid evaluation in all-source procurement. So those are some other time-of-delivery factors that we looked at.

Why are the assumptions, methodology and calculations used in developing TOD factors not available in the public domain? So, the proprietary nature of them.

What modifications should be made to make TOD factors more easily benchmarked and to insure that TOD factors help the state achieve 20 percent renewables by 2010?

So those are the questions that we're tasked with. And I think we'll just go, again, probably through the order that's listed in the agenda, which, Paul, puts you up.

MR. DOUGLAS: Thanks a lot. Regarding to the first question -- so, we're just going to go first question and go around the table? That's what you're thinking?

MR. PRICE: I thought we would do just the whole thing. Everybody else -- we can do that, too, I suppose, but --

MR. DOUGLAS: Preferred approach would be just to go through the first question, go around the table, but that's up to you. What would you like?

MR. PRICE: One question, and then we'll go around? Okay. Sounds good.

MR. DOUGLAS: Regarding the first question, you know, do TOD practices dissuade potential bidders. From our experience in the last six months we have met with probably a dozen developers. We have had numerous conversations with the utilities on this topic.

And so the overarching message that we're getting is that SEP financibility is a concern. Specifically, the process, issues regarding confidentiality, and whether the funds, once they're awarded, could be clawed back by the Department of Finance.

So I would say yes, I think the TOD practices could be a barrier for bidders in the context of the SEP award.

MR. GONCALVES: Well, I think that's partly, you know, a lot of these questions were from us at the Commission. So I think a lot of it is, from our standpoint, we do have those questions on whether and how it may affect potential bidders. And I think I'm probably going to leave it to most of the others to respond to that, and sort of take in the information.

MR. McGUIRE: Patrick McGuire from CalWEA. I don't think that the TOD factors are a huge issue for us, particularly as the TOD factors in the MPR model are the same as what were used in the RFO for 2005.

It's only in the 2006 RFO where you see Edison with this plus, you know, over 3.0 onpeak factor. And I think a lot of that is related to how they've structured their capacity pricing.

In the comparison we saw the avoided cost QF TOD factors are very similar to the ones that are in the MPR. And the fact that there is consistency provides a lot of assurance.

And I would also just add that CalWEA is very happy with the MPR process at the PUC in general. It's one of the most transparent things that's out there; you can really take a look at it and see every single parameter and see how the numbers are developed.

So, really, the TOD factors are one of the less transparent elements of it. But it is based on the utility's analysis of forward market energy prices. And you can see how that's done. And that's something the Commission could do, itself, in fact.

So I don't see a big problem with dissuading bidders. I think if the factors get extremely peaky there is an issue. Like, for instance, wind would face a risk of having to collect its money in a very short period of time. These very high factors could be a problem, but the 2005 ones look pretty good.

MR. KELLY: This is Steven Kelly. I have heard a lot of comments about the time-of-day factors. Either, I think from the Commission's perspective, the way you should look at these is they do have an impact on various technologies. And when they deliver. It's really a signal to the developer saying, from the utility saying I want this power at this period of time and I'm willing to pay a premium to get it.

And if they're very peaky and you've got generation that can follow those signals, then you'll see people that won't operate in offpeak periods, save fuel, and plan to be there in the summer. I mean the hypothetical is that if you have a generator is going to get all its money in one hour of the summer, you can damned be sure he'll be there if that's the price signal.

So, this is more an issue of really incenting certain types of technologies that you might want to see show up in the marketplace.

Peakier time-of-day factors will have a greater influence on incenting what we look at as intermittent resources, wind and solar, that can deliver during those time periods.

Baseload units will operate 7-by-24, and don't necessarily respond to that unless there's an incentive to save some fuel in the offpeak periods.

The issue about the relationship between the time-of-day factors and the SEP payments is not something that necessarily, I think, impacts bidders. Because bidders don't know what the MPRs are when they bid. What they really want is certainty that if the SEP payments are triggered, they're going to receive them. And that's an issue that hasn't been tested yet really, the extent to which you can finance against SEP payments that are being triggered by peaky or less peaky time-of-day factors.

But on a whole, I'm not sure it's necessarily a problem, but it can be used to incent certain technologies that the state might want. It seems to be doing that now.

MR. MORRIS: I would hope that current TOD practices do not dissuade potential bidders, although I don't have any personal experience in that. I do know that bidders understand that energy values are different at different times of day and different parts of the year. Bidders are asked to provide their projected output profile, and they understand why that's a part of the bid and how it plays in.

So, I would hope that it wouldn't dissuade. I don't think that there's unnecessary complexity. And I don't think that the TOD factors are to blame for the problem of the unfinancibility of SEP payments. Whether you have TOD factors or not, you're still going to have the issue of if the particular contract needs SEP payments, what does that do to the financibility of the project.

So, while the TOD factors can influence what those SEP payments are, the mix between the utilities' part of the revenue and the SEP part, the basic problem with the SEP system and its financibility if not a problem of use of TOD factors.

MR. KUGA: At PG&E we have not heard from potential suppliers that the TOD practices are unnecessarily complex and hindering their ability to submit bids.

What we have heard, as Paul mentioned, and as Steven mentioned, is the concern about the financibility to the extent they influence the amount of SEP payments. As Snuller's paper and presentation indicated, there could be substantial differences in the SEP payment requirements for a similar bid price to two different utilities, namely Edison and PG&E. And that significantly impacts potentially the viability of our project from a financing standpoint. So that is of concern.

The payments levels, while the same on a pricing basis, can result in dramatically different results. Now there are different reasons for, and I think it's been pointed out very clearly why there are differences between the approaches between the three utilities. Perhaps over time we should strive for a common set of avoided costs and common TOD factors for evaluating all resources, both supply side and demand side. And I believe the CPUC and its avoided cost phase three is striving to achieve that objective. And I think we fully support moving in that direction.

ASSOCIATE MEMBER GEESMAN: Would that be a common set of values on a statewide basis, or would it still vary utility by utility?

MR. KUGA: Well, I would say, you know, we have a common MPR on a statewide basis. We could potentially move to a common TOD factor.

But I think we recognize in the valuation, which includes some of the proprietary for price curves and distribution over each hour, the valuation may be slightly different from utility to utility.

However, the concept of perhaps a standardized TOD factor for payment purposes could make sense. It would help eliminate some of the disparity of financing concerns between the utilities for the same project.

If directed, PG&E would be not opposed to using the common, like Edison's TOD for payment purposes. And as Steven mentioned, when you look at the TOD differences, one could view Edison's approach as incenting a certain type of profile for deliveries.

From PG&E's perspective what we try to do is represent the value of the generation to us in our TOD factors.

MR. BARKER: Dave Barker, SDG&E. Basically the TOD factors moving from having two MPRs to having one MPR with the TOD factor is seen as an improvement for us. A little bit easier to evaluate.

The whole SEP payment issue, I think, is separate. I'll leave that for the panel two discussion.

So, from our point of view, moving to the TOD factor from the two MPR was a good thing.

As far as a common set of TOD factors, I'm not quite sure that SDG&E is there. We want to have more energy produced; if you have very peaky TOD factors, then you encourage people to shut down. We want more renewable energy, so we don't want them to shut down. So I'm not quite sure that it fits all utilities, one common TOD factor, if it's patterned very peaky.

MR. HEMPHILL: I think the original question was do the TOD factors dissuade bidders. Our experience to date has been no. In fact, we've been told that people said we've got it right.

And in terms of the other issue that's been brought up in terms of common TODs, we typically -- I mean what we do in our valuation is look at the contribution to reliability. So it's clearly, from our customers' point of view, where do we need the power the most. It's not meant to be an incentive, but it certainly does give that impression. But it's a valuation of the contribution to reliability.

I believe that's the common goal that PG&E also has, but we also have probably a different circumstance than PG&E and San Diego do, and our contribution to reliability is greatest during the summer onpeak. And so that's why you see the type of shape that you see in our valuation.

MR. PRICE: Okay.

MR. KELLY: I'd like to comment real quickly on this issue of a common TOD, though. Because I recognize that all the utilities have different needs, and these TODs are supposed to reflect that. And I understand that.

But one potential thing to think about is that if there were common TODs that could be agreed by the utilities, the state is moving to allow the utilities to swap resources to meet their RPS. We may be moving towards more of a

REC-based market, which is essentially a more formal way to swap.

In that kind of environment, if you had common TODs then you would be theoretically getting, sending signals that would equate the value of the energy delivered at the right time, so for the swaps, when it occurs, so that PG&E's got a swap going -- got a contract with somebody in southern California responding to PG&E's time-of-day delivery, at least Edison would be understanding that those deliveries are going to occur during that time. May find it beneficial, may find it helpful from a reliability perspective. It's just something to think about.

DR. McCANN: Richard McCann with M.Cubed. I want to follow up on that, the common TOD question, which is in my experience working across utilities in terms of in their rate cases and proceedings like that, the differences between the utilities, I have found, is not usually in the data or the situation of the utility. It's actually in the methodology that the utilities are using. That the differences are not reflective of different preferences of the utilities, but it's actually how they actually do the calculations in their work papers.

And you can take one set and put all the same numbers into another utility's model, and you'll come out with a very different answer.

But there's also, one of the things about the common methodology, though, is I think that it's important that it be a methodology and not numbers. That the numbers aren't going to be the same between the utilities, because they are going to be different situations.

San Diego's got, they've got a more isolated market so they're going to be concerned about having more inservice area resources. PG&E has a more diverse load profile across its service area.

So you're going to have different factors that are going to come out of a TOD. But there's also one other thing about having common TODs and having common methodology. It goes beyond the REC, because it actually, the greenhouse gas emissions cap, as well, will be affected by what the TOD factors are that come out of the RPS.

So that -- because renewables are going to be part of that greenhouse gas trading program, as it is eventually adopted by the PUC. So that's another thing that you need to keep in mind, is that it's going to be more difficult to have trading when you have one utility with a peak TOD that's twice what the other two utilities TOD factors are.

MR. MORRIS: If I could just also follow up on this. While we certainly do derive incentives and price signals from the TOD factors, I think it's important to keep in mind that the idea of developing and using the TOD factors is to try and reflect the actual value of energy at the given time.

And so if those TOD factors are, in fact, properly constructed and reflective of the market, it insures that the utilities are paying a reasonable value at any given time, and that the producer is receiving commensurate value at any given time.

As far as a statewide single TOD factor, and thinking again in the theoretical economics regime, I think if we had no transmission constraints within the state, we would absolutely expect the TOD factors for each utility to be about the same, because the price of energy all across the state would be the same.

We do have transmission constraints; and that does differentiate the different utilities. The different utilities have different annual demand profiles; and those different profiles will reflect where different utilities value energy differently.

So I think at this point in time, even if you had a common methodology, you would probably expect some differences among the utilities and their profiles. But it doesn't have to be market.

MR. PRICE: Thank you, all. I wanted to change it up a little bit. We've got a number of other questions that are on TOD factors, and I think there's sort of a group of questions on proprietary nature of the calculation of the TOD factors in particular.

So I wanted to go around and have folks address, you know, whether they feel like it's appropriate for the TOD factors to be proprietary. Any of the other questions on TODs that you want to bring up, also address those.

I think we've heard a couple threads that we want to make time to talk about, which is the financibility issue; the technology issue; and the sort of data-versus-methodology issue that has been brought up.

So, to finish out this list of questions here, anybody who wants to talk to the proprietary. Or we should go around and talk about the proprietary issue. Paul.

MR. DOUGLAS: I think actually a couple months ago the PUC issued a decision on confidentiality. And I think in the matrix attached to that decision there are inputs for various calculations specifically such as for market curves, that were identified as confidential data.

So I'm not an expert on confidentiality, so all I can do is quote the decision, and let the utilities speak for their own material.

MR. GONCALVES: Yeah, I think that sort of from our standpoint, I mean the more that is transparent the better off. I do understand the need for some confidentiality, and I think this is probably one of those that's better addressed by the utilities.

But more transparently, the better off I think everybody is. Of course, that needs to be balanced sort of with the proprietary information, which I think mostly is probably going to be covered by the IOUs. So I'll sort of give more time to everybody else.

MR. McGUIRE: Pat McGuire. You know, I'm always in favor of more transparency wherever possible, although it's -- probably we're going to hear from the utilities why it's completely understandable that if they're going to do their own forward analysis of the market, and then array that into hourly numbers, that that's kind of a confidential exercise. But I think the data that's needed to do that kind of exercise is generally available.

And, you know, I just -- obviously just emphasize my favor for transparent, you know, process. The ISO will be having MRTU in the future, and we should be seeing hourly nodal prices all across California. So there should be additional guidance coming up.

MR. KELLY: I think I'm a market participant so I can't sit next to Stu.

(Laughter.)

MR. KELLY: I mean I don't think this is a time-of-day thing, a delivery issue. Bid evaluation is critical, the extent to which I'm presuming that there's some methodology that they're running numbers and people are popping up. Bid evaluation is very critical and very important; it should be more transparent. How it is impacted on the time-of-delivery factors, I'm not sure it's as critical as the other things.

MR. MORRIS: I guess I'm next. I think there's way too much confidentiality in the TOD process. One can easily derive pretty accurate TOD factors for each utility based on their known demand profiles, based on known data sets.

And we're not talking about the actual gas forecast, which has more legitimacy to be confidential. But we're talking about how to distribute any given year's price across the hours of the year. And I don't understand why that needs to be a confidential distribution.

MR. KUGA: All right, I'm a big fan of confidential information for proprietary and commercially sensitive information and disclosure of other information.

The TODs represent an aggregation of confidential information. And the reason that the hourly profiles are confidential is we are active in ongoing negotiations, not only in the renewable community, but with other market participants, to meet our net open position.

And the information allows folks to better understand our willingness to pay. And, like I said, we're involved in the negotiations, notwithstanding a bid solicitation process, there are bilateral negotiations associated with each commercial transaction.

The sensitivity of the information, like I mentioned, relates to customer, what customers will end up paying. And, again, we look at protecting the interests of the customers on one hand, and getting the best deal and promoting the renewable policies as well as other state policies in the same process.

So there is a tradeoff and a balance. We believe the TOD factors represent the value to PG&E and its customers, and our willingness to pay. And in aggregated form, that's what's there.

We provide to non-market participants under nondisclosure agreements the detailed information. And that is available to the non-market participants.

To the market participants, since we are in negotiations, you can hopefully understand our reluctance to disclose our willingness to pay.

And the valuation process, as Steven mentioned, TOD is one of a number of factors in the valuation process. PG&E has laid out in its bid protocols the criteria. I believe there are eight or nine factors that we consider, including credit and project viability, technology viability for example, in the valuation process.

Again, we go through a scoring process with market participants who execute the nondisclosure agreement and provide the information to both Commissions under confidentiality provisions.

So the information is made available to both regulators and non-market participants with the nondisclosure agreements. I'll just leave it at that.

ASSOCIATE MEMBER GEESMAN: Roy, when Snuller puts up a chart that shows that in general the utility TOD factors track the Energy Commission's time-sensitive values for building standards and track the avoided cost calculations made by the PUC, isn't about 90 percent of the cat already out of the bad?

MR. KUGA: Well, if that's the case, then we shouldn't be having the discussion about whether additional information is needed. From our perspective, again, that hourly profile is highly sensitive, commercially sensitive. And it does affect our valuation.

And if market participants had that, they'd know how to price offers to us.

ASSOCIATE MEMBER GEESMAN: Now, last year's data for PG&E is public, is it not? I know it was on a chart earlier.

MR. KUGA: Not the hourly information.

ASSOCIATE MEMBER GEESMAN: The seasonal.

MR. KUGA: Right. And the QF information has been out there for awhile; the methodology has been established for a number of years, probably 20 years in terms of the time periods. It has a different history. We'd like to see us move all in a consistent approach and methodology going forward. We're not there. But, again, I think we're making good headway to get there.

MR. BARKER: For SDG&E we sort of took a market approach to it, so that it follows the CPUC avoided cost hourly profile. And the only thing that's proprietary is the use of forward market information about onpeak and offpeak. And we have agreements with the brokers not to provide those data publicly.

So it's not that we're not willing to provide it, it's that we have agreements that we won't provide it, with the brokers.

MR. HEMPHILL: I think we've made most of ours publicly available at SCE, which is we talk about the process and we do show the output. There are some sensitive input information. We've described our process many times, and we've had many many data requests on that, and provided, you know, great, I think, documentation of it.

There is sensitive information, it's the input. And that can impact how people will bid, or negotiate with us on bilateral deals, both in the real time or the shorter term markets, and more in our longer term markets with renewables. So that's where we have a sensitivity.

MR. KELLY: Just as a followup that when I think of the issue here, and time-of-delivery factors being one of many of the factors the utilities are using to evaluate and rank order the bids, in one sense it's not so much how do they calculate it, because, you know, these things are what they're telling the marketplace they want when they want it.

But it probably would be helpful, and I don't think this is being done today, to know that when you bid, for a bidder to know that when the time of delivery, your ability to match the utility's time-of-delivery needs is going to be 40 percent of the evaluation criteria. And your local community impact is going to be 30 percent or something like that. I don't even think that information is out there to tell bidders where to emphasize when they submit a proposal of the various factors the utilities use.

I know PG&E, I think they list out seven or eight categories of things that they consider; most of that's in legislation. But the relative weights of those are not very transparent. And I think that would be helpful for bidders to know.

I should focus on making sure my units are there when they want them. And that's more important than something else that they're looking at. That's something I think is missing today, and would be helpful for bidders.

I know when you bid to, you know,

Department of Energy or Department of Defense stuff, they will tell you, you know, this factor is going to be weighed 30 percent, this factor is 20 percent. And that gives bidders some idea of what they should emphasize when they put their bids together. That's missing now, I think.

MR. DOUGLAS: Steven, I totally agree with you. Actually I think the Commission has issued a scoping memo yesterday that actually would parallel your thinking that there is a need for greater transparency on least-cost/best-fit methodology.

Regarding the underlying of the before market curves, as I said earlier, I think the Commission has identified that as confidential. But the overarching methodology for evaluating bids, we agree. And the utilities have been ordered to file a detailed description of their methodology.

And also we're having workshops at the end of October asking -- well, the utilities don't know this yet, but we're going to ask them to --

(Laughter.)

MR. DOUGLAS: Sorry, guys.

(Laughter.)

MR. DOUGLAS: Advanced notice, you're coming in. And explaining to the parties how the process works. And then we're going to ask the utilities to explain the process, ask the parties where they think there's lack of transparency. Then somewhere in the middle we're going to hold this confidentiality decision and say, well, unfortunately the Commission's ruled on this.

But if it doesn't address that issue, we'll ask the utilities to make that more apparent in their filings.

MR. HEMPHILL: Just to be very clear, we've had workshops on this very subject where we've laid it all out and answered questions to all the renewable bidders. We've made that available. So, you know, happy to do it again, Paul, but this is something that we've done anyway.

DR. McCANN: Just two comments on this discussion. One is that the -- I'm concerned about the lack of reconciliation between proceedings about the TOD, that the TOD factors look different than the TODs that are used in the GRCs, for example. That the rate structures that are put out for customers look different than the profiles that are being paid to the generators.

And there is no cross-pollination between these proceedings about that. And it spills over into energy efficiency, as well. How do you evaluate energy efficiency against generation when the load profiles are not the same between proceedings.

And transparency is basically probably the only way that you can get those to be reconciled between them.

The other thing is I'm a bit concerned of the reliance on brokers for forward price contracts when we're talking about TODs for 20-year contracts. That the TODs that are being prepared for the RPS are long-term contracts, not contracts that are being -- or not for short-term forward purchases that brokers are going to be aware of.

And so as we talked about, this was a question that was brought up, I think, at some point in the proceeding. Well, how long does the TOD apply for. Well, apparently it applies for 20 years in these contracts. That means you have to approach the TOD structuring much differently than you would for a contract that's going to be for next year or two years forwards contract. The TODs are going to look very different.

And so those are two things in particular that I think that need to be addressed.

MR. MORRIS: If I might even amplify that a bit. It makes even more sense to tie the TOD profiles to the demand profiles because in the long term, and certainly if you want to be an economist in a perfect market that's how it should be related.

But it's also important for everybody to realize there's not that much opportunity for people to manipulate the output of their renewable unit based on whatever the TOD profile is. If you're a solar generator, you're going to generate when the sun's out. If you're a wind generator, you're going to generate when the wind's blowing. And if you're a baseload generator, you're going to generate pretty much all the time, except for scheduled outages.

The one potential source that might do a little bit of up and down in response to that TOD profile is the only renewable that actually buys its fuel, which is biomass. But biomass has been somewhat protected from that anyway by the way that the support payments, at least in the existing program, has encouraged them to generate during the offpeak periods.

So, this is really in general not a place where generators can manipulate very much.

DR. McCANN: One other thing I want to follow up on that I forgot about. On the confidentiality issue, now that we're going to have AMI all around, basically a customer is going to be able to download the utility's profile information.

Eventually, because you're going to be sending out hourly price signals back to the customers, the customers are going to be able to plug in and have hourly price signals back to them. They're going to be -- every one of these bidders is a customer. So they're going to have all of that data anyways.

They're going to have the load profile; your existing price profile data. And they're going to be able to turn around and use that in their bids going forward.

So, you know, the installation of AMI means that you've basically opened up your books to a lot of that proprietary information.

MR. KUGA: I don't understand. As a customer I won't be able to get your profile or Paul's profile.

DR. McCANN: No, but I will be able to get the hourly prices.

MR. KUGA: Yeah, and actually the entire market will have that through the ISO.

DR. McCANN: Right. And then the ISO also will have all the load profiles -- you'll be able to get the load data. But you'll be getting a lot of that information that is off of that.

MR. KUGA: The hourly load profile on a real-time basis is not available. Maybe on a recorded basis it's disclosed, after the fact. But on a real-time basis you can only get your current, your information for yourself.

DR. McCANN: Right, but when you're making a bid you only need the recorded data; you don't need the immediate load profile data. You only need a recorded set that's fairly recent in order to be able to work back through what the utility load profile looks like.

And by having AMI you're opening yourselves up quite a bit to having a lot more data available to customers and bidders.

MR. KUGA: Well, I think some of the recorded hourly data is already in the public domain.

DR. McCANN: Um-hum.

MR. PRICE: Did anybody else have more on confidentiality?

I wanted to, if it was okay, go back and pick up on a trend that we sort of talked about the first time around, which was the fact that different technologies tend to fit the time-of-day profiles better.

And so are we appropriately incenting the right types of technologies, or perhaps we want to be trying to get the most energy, which is how the RPS goals are set. And so the appropriateness of the TODs to technology.

I think that -- is that a clear enough, is that a clear enough question? Paul.

MR. DOUGLAS: The PUC's position on various renewable technologies that the RPS program is resource indifferent. So, basically it is, you know, you bid your profile; you are a certain technology; you're compared to a TOD profile that reflect the market price of electricity in certain hours. And, you know, you're compared against your brethren renewable technologies, and how you stack is how you stack.

If somewhere further down the road we decide we want to carve out for particular technologies, so be it. But I think at the moment the Commission, its official position is that it's resource indifferent.

ASSOCIATE MEMBER GEESMAN: Has that changed at all in view of the Governor's recommendation that we create a biomass set aside?

MR. DOUGLAS: We -- well, as I mentioned earlier, we've issued a scoping memo, I think it was yesterday. And there is actually a section in there asking parties for comment on how to integrate this biomass initiative into a program that's theoretically resource indifferent.

MR. GONCALVES: I think as far as the Energy Commission goes and SEP payments, given that the PUC process is, the MPR is technology indifferent, I think our process, once it gets here, really is, at this point, also technology indifferent.

As far as the TODs and sort of the variance in the TODs, you know, I don't think they are designed, or should be necessarily designed to incent a certain technology. However, given the needs and summer peak and so forth, and time periods when generation is needed, that it probably is appropriate to have the TODs reflect the need, and when the generation is most needed, and to incent generators, no matter what technology they are, to operate during those time periods.

MR. McGUIRE: Maybe I can just relate this question back to the confidentiality issue, as well. You know, the MPR, in a sense, is not just the average cost of a new combined cycle generator, it's also kind of an idea of where the market ought to be at if we were in an equilibrium; we weren't long or short on capacity, then you might expect market prices would equal average cost.

TOD factors, kind of the same issues there. Even though we're not using a peaking MPR anymore, that's been thrown out, we have TOD factors. You can see in the long run there might be a set of TOD factors that do reflect a long-run equilibrium.

A hot summer like last July where, you know, we had a heat storm, you could see the onpeak TOD factor could be immense. But, over time, you might expect that there'd be a long run average that makes some kind of sense.

I don't know if figuring out those long-run average numbers would be anything to do with anything confidential, or looking at forward numbers.

I'm sorry to jump ship on this and to go back to that discussion, but it just seems to me that the question about technology indifference, the PUC can be indifferent to technologies, but nevertheless, you've got to be aware of the TOD factors; if you adopt an extremely peaky one, you could very well be driving the boat.

So, I think, you know, there is a longer run problem that's interesting and worth studying, which is when you have multi-attribute auctions it's had to set fixed values on the various attributes without knowing the degree of your competition within each of those bins. So this is something that should be looked at over time. And here we are in only the second round of solicitations.

MR. PRICE: I just had a quick followup. Thinking about wind technology in particular, are we incenting wind generators to site in areas that have wind during higher value TOD periods and sacrificing energy output from the facility?

I know that it's learning there, but is that --

MR. McGUIRE: Well, wind is an intermittent sort of baseload resource; probably wouldn't respond to these kind of concerns. You know, solar, for instance, would really respond to it, a very very peaky TOD.

Now, as far as location I don't think we're really talking about that. But the TOD factors, that's more of a time issue.

ASSOCIATE MEMBER GEESMAN: Well, thus far it would seem that we've used economic values to try and rank order our priorities. If, in fact, climate change considerations end up becoming more prevalent as motivators for these programs, that may change the way the state strikes the balance among priorities.

MR. KELLY: This is Steven Kelly. I think that's correct, Commissioner Geesman, what you just said. There's really two factors that seem to me that are probably going on in the calculation of the utilities when they select winning bidders. It's the reliability that Stu was talking about; it's also the need to meet the RPS obligation, which is measured in basically energy delivered.

And the extent to which those overlap, that's good. But they may not in certain cases. And these TOD factors can have an impact on how much is actually delivered.

It also may have an impact on creating a situation where certain resources are selected that, you know, we need to keep focus on the issue is getting stuff built and delivered. So we want to look at TOD factors to make sure that it doesn't create an environment in which a lot of stuff is selected, but none of it's going to get delivered in a timely manner. Either it's locationally constrained, transmission constrained or whatever. Because then it makes it harder to meet the RPS obligation in a timely manner.

So that's something I think that this TOD factor could have an impact on.

MR. MORRIS: Again, I don't think that the TOD factors will influence how anybody operates with the possible exception of biomass, the only renewable resource that actually has a high variable operating cost; and therefore, can respond to these kind of signals.

The TOD factors should be used, again, if they properly reflect value at a given time, to differentiate among different project proposals. And in particular, because most profiles are very predictable without even knowing where the site is, the exception is wind.

Proper TOD profiles should help to motivate wind generators to pick the best sites where you define the best sites as being the ones whose profiles provide power at the most valuable times.

I'm not sure that our current system of large time-of-use periods actually provides the granularity needed to select among those sites. For example, a wind site that peaks in June and a wind site that peaks in August right now would be evaluated the same because those time periods are the same. But we know that that August energy is worth much more than that June energy.

So I think with more granularity in the time-of-delivery profiles we would do a better job of being able to select the project bids that best meet the utilities' demand profiles.

MR. TUTT: Greg, can I break in there and ask, I don't think the question necessarily is related only to whether a renewable resource can change the way it operates related to these TOD factors. The question, I think, is can it bid a profile that's different than it will actually end up having in operation.

And in so doing, can it, therefore, change the MPR and in some way gain or otherwise get an advantage over others.

MR. MORRIS: It won't change the MPR, because the MPR is 8760 average.

MR. TUTT: But the MPR -- excuse me, is based on the profile of the bid, isn't it, for that particular project?

MR. MORRIS: Well, the adjusted MPR, okay. It would change the adjusted MPR. Again, wind is really the only resource that would have the latitude to play a game there, because, you know, solar profiles are pretty predictable and everything else is baseload.

But the good thing about it is that we sort of have a self-protective mechanism. If somebody bids a profile different than what they really predict they will have in order to make their bid look better, when they come in with the profile that they in fact have because that's what their site makes them do, they'll be paid less than they expected to receive.

So, that helps to protect against that kind of manipulation. But there's always some ability to do that, and I would hope, and I don't know how the utilities evaluate these bids, but I would hope that they would look at the quality of the wind data because it's not something that somebody simply is supposed to be making up to make their bid look good. But how well does the bid data, the wind data for that site actually how well is it documented and constructed, should be a part of that evaluation, I would think.

MR. KUGA: I agree with your comments there. We would evaluate the viability of the profile being submitted. And the wind generator or whoever bids a profile different than deliveries, they get paid based on what they deliver, not what they bid. So there's some self-correcting element there.

With respect to the TOD factors, I think the way we look at it is in the context of least-cost/best-fit. And I think your comments earlier, Greg, about do we end up paying for the power based on what it's worth, based on the delivery pattern. And that's what we're striving to achieve with the TOD factors here.

For a facility that is baseloaded, the TOD factors really don't matter. It just washes out to a 1.0; like biomass, they'll get paid effectively the MPR price.

But for certain intermittent type resources, it does make a difference. And we will look at the delivery patterns based on the bids.

However, the TOD, in itself, we think is a consideration, not a driver for site location. I think wind developers look at wind-rich sites as solar developers look at, you know, heating values associated with the solar radiation. Transmission is a consideration to the extent the interconnection costs can be significant. They do affect some siting decisions.

So, in a well of consideration I don't think it's a large driver in terms of siting of the resources.

So, again, the appropriateness, I think it's necessary to reflect a value relative to the pattern of delivery. That's what we're trying to achieve here. Just short of an hourly price. And providing some certainty over the duration of the contract so financing can occur.

If we say we'll just pay the ISO hourly price, that's fine; that will pay what it's worth. But I'm not sure any lender will be able to finance that bet, you know, or that profile on a forward basis.

MR. HEMPHILL: Just to continue --

MR. TUTT: Can I --

MR. HEMPHILL: I'm sorry.

MR. TUTT: A couple comments back to the question of whether, as you generate you have a self-correcting mechanism prior to your bids. As I remember in the BRPU there was perhaps a different generation profile, and it wasn't entirely self-correcting. So, I guess, I mean part of the concern, I think, about complexity comes from trying to understand whether there are circumstances where somebody might come up with a way of bidding and then generating in a way that isn't self-correcting.

I had another question which is related to the different time-of-day profiles among the utilities. If I, as Tim Tutt Power, was able to tell the utilities I'm going to bid in, in effect I have a resource that I can bid in a peaker, just like the peakers that we've been ordered to pursue for next year, I've got a 49.5 megawatt peaker. It's a peaker profile. And I do a time-of-day profile for that peaker.

Will I come up with something where I'll have a different -- will match, in effect, the cost of a peaker, which is what I understand the MPR is supposed to do? Or will it be some other number, depending on the utility? Will I be getting the SEP payments even though I'm below the cost of a peaker in some utilities or not?

MR. HEMPHILL: Got a lot of sub-questions in there, Tim. For SCE, you know, we would evaluate your bid with all the others, including time-of-day factors and credit and collateral. A lot of other, transmission, a bunch of issues.

At the end of the day it's all about kilowatt hours. And so whether yours is successful or not, it's probably not going to displace anybody else's. Because if you're just producing the six hours where you can maximize your single payment, we're still out for getting kilowatt hours. You may or may not, you know, be successful in your bid, depending on how you priced it. But we will be continuing to look for kilowatt hours beyond those that are just producing during peak time.

In our -- we're now doing our fourth solicitation. We've had every technology be successful through the process. So, it hasn't been -- it's been technology neutral and it's produced robust results across all technologies. That's been our experiences to date.

MR. PRICE: Tim, I can answer, I think, your first question based on the work we did on the mechanics and whether there's the gaming issue.

The generators get paid in two pieces, right. The one piece from the utility and that payment is equal to the base price times the TOD factor for the energy they deliver in each period.

So, if they bid, oh, my wind farm is all going to be generating on summer peak. That's fine for the bid, but then when the actual payment comes, it's the energy they delivered in each period times the base price times the TOD factor.

So that's the self-correcting piece.

The SEP payment piece, to the extent it's fixed, based on the bid profile, okay, could be higher if they, and this is what Tony's analysis showed, the SEP payment could be higher if the bid profile is different than the actual output.

And your other --

ASSOCIATE MEMBER GEESMAN: How do we reconcile those?

MR. PRICE: Sorry?

ASSOCIATE MEMBER GEESMAN: How do we reconcile those? I hear this as just another source of constipation in the SEP process. And we have identified the SEP process as a design defect in this program.

How do we reconcile the necessity of having a time-of-delivery variation on, I think Tony's, and frankly, the Commission's desire, to prevent a raid on the bank in terms of the SEP account?

And there don't need to be answers today, but people ought to file written comments giving us suggestions a to how to protect against that scenario.

MR. KELLY: You know, I don't know that

I have any suggestions now, because this isn't really a generator issue. I mean what the generators are looking for is a revenue stream or revenue streams that are going to pay back the cost of the project, plus the variable costs at a reasonable rate of return. That's probably a fixed number.

When the time-of-delivery factors are known, they can take their expected generation profiles, look at when they're likely to operate, match those against the time-of-delivery factors and find out if they're going to get enough money, or they think they will. And then they're going to bid.

And, you know, particularly for those who don't have any fuel, if the time-of-delivery factors drop below 1, they may not care because they're not losing anything because they're not buying fuel.

The ones who really do care are the ones who are buying fuel at that time and paying X for it. And if they aren't getting money at that time to repay that cost, they're out of luck. That's a bad situation to be in. So that's why they want to know this stuff.

But really what you're talking about is you're going to bid as a bidder, you know, here's my price, this is how it's going to be allocated over the course of the year by these time-of-delivery factors based on my expected operations. But the reality is I need $20 million to make this project go. I would like to have it all from the utility because there's some question about the financibility of the SEP payments. And that hasn't been tested yet.

But you really want to make sure that you're going to recover those costs. And when you get them, it's kind of indifferent as long as you're pretty confident you can operate in the periods to make sure you achieve those revenues.

MR. PRICE: I'm not sure we gave Dave or Stu a chance to talk about the technology piece. That's okay?

MR. HEMPHILL: I'm fine.

MR. PRICE: I had one other question that I was going to pick up from the thread, but then I thought after that we can, maybe the Chair, Commissioners, have questions also.

And the question I wanted to pick up on that we started on early was the financibility issue of the SEP payments.

We've heard a couple times today that the financibility is a big issue. The analysis that I presented earlier showed that as long as the SEP payment money is just as good for the financial community as the utility payment money, that the generator is going to be paid -- they can basically bid the total amount that they want to get paid.

So to the extent that they're equally financible, then we're talking about the same cash flow stream, right. So the differences between what's MPR-adjusted and SEP-payment-adjusted is really how the financial community perceives those two pools of money.

So, again, I thought I would go around and talk about, I guess, from people's perspective whether they feel like financibility is a big issue; and then what are the factors that are driving the problem with financing SEP payments.

MR. DOUGLAS: I'm not an expert on project financing, so I'm just going to talk from my experiences with meeting the developers and hearing their concerns.

The net effect of some anxiety regarding financibility of SEPs, the net impact is that the MPR acts as a price cap. Moreso for peaking technologies. Had a couple conversations with solar developers where, you know, they're trying to figure out ways to structure.

I agree with you, Steven, really all they care about is they just, at the end of the day they're made whole. They are really indifferent where the money comes from, as long as they're made whole.

But then as soon as you bring in the issue of a piece of their cash flow might not be financible, then they need to really reexamine how they're structuring their bid. That's quite a few conversations we've had with regards to the '05 contracts,a nd how to structure the payment stream to actually get them below the MPR.

And I think the net result is sometimes we actually have to, one option might be take it as a bilateral so they don't have to be compared against the MPR.

At the end of the day they are still reasonable relative to the MPR, but then they're not compared to the MPR because we might have to do some type of indexing so they can bring the prices down. So, that is, from our experience, the impact of SEPs.

Specifically with regards to project financing and SEPs, I can't talk on that.

MR. GONCALVES: The issue of financibility is definitely something that's come up at all of our IEPR and RPS workshops so far. And I think it's been discussed somewhat and is definitely a concern of the Energy Commission.

I think from kind of not an expert and I mean the recap sort of consensus is that if the SEPs aren't financible then, you know, the projects just can't count on that. And that makes that whole -- the SEPs, puts that amount of money sort of in question if they can't take that to the bank and use that for financing purposes.

And I think that issue has been brought up numerous times by all the stakeholders. And not being an expert, I'll let them sort of add on.

MR. McGUIRE: I am not a SEP expert. I'll just say that, you know, I think the 2005 MPR is a huge improvement of the 2004 MPR. And that it got the number up to a reasonable level. There was a concern that if the number's way too low the SEP funds would get eaten into much too quickly.

And I guess a similar concern would be really really peaky TOD factors. We just want to make sure we don't use up the money on one single big project, and have financibility problems. It would be nice if that pot of money is just as good as utility money.

MR. KELLY: My general understanding is concern the development community has is what the Legislature giveth they can taketh away at anytime. And there isn't really, whether it's grant program from the state, or an account that's in trust or whatever, there's a lack of certainty that that money is not at potential risk over the course of the contract term.

At a minimum that raises the price, because the bidders have to manage that uncertainty. So that is a problem. And, you know, obviously we probably need the financial types here to tell us whether that's an accurate perception in the financial community or not. But that's what I'm hearing.

The other thing about the SEP payment, though, that's interesting is that, you know, there's not much involved. The SEP payments have the added impact of triggering prevailing wage clauses and so forth, which may or may not have been bid in. And that can adjust your costs.

And I don't know if people are bidding in two bids or not for under the assumption that they might trigger some SEP payments. But that could be another added uncertainty that's caused by SEP.

MR. KNOX: We may want to save up the last few minutes before the lunch break for public comment, if there is any. I don't know if there are any persons on the telephone link that would like to comment?

ASSOCIATE MEMBER GEESMAN: Or anybody in the audience.

MR. KNOX: Or anybody in the audience, of course, as well.

DR. McCANN: I just wanted to add one comment on the SEP MPR issue. That one way of addressing the SEP issue is to look at it as instead of trying to finance the SEP payments, return on equity in doing the calculation.

But that means that you have to go back to the MPR and instead of assuming that you have the financial assurance of having a long-term contract with the utility which lowered the rate of return that was in the MPR model, you have to move to using a merchant plant return, or something perhaps even riskier in the MPR calculation. And then you make the adjustment in the MPR calculation.

And that boosts it up to take into account for the risk within the SEP. And so that's the adjustment that you could probably make.

MR. MORRIS: I think the SEP payment issue is a really fundamental flaw in the RPS program, because there's no simple fix to make a payment that's probably not financible, financible.

And that is something that really ought to be thought about. And it's really entwined with the issue of whether or not we want to change to a compliance program based on bundled tradeable RECs, which if the RECs had a value of their own, there wouldn't be a SEP payment, and there wouldn't be a SEP program.

So this may well be a fundamental flaw in the program that deserves thought and possibly fixing.

ASSOCIATE MEMBER GEESMAN: Greg, you

don't think that the financibility issue could be addressed by segregating a SEP award in a third-party escrow?

MR. MORRIS: That's beyond my expertise. It might be. I don't know what your ability to actually pull that off is. I've heard you --

ASSOCIATE MEMBER GEESMAN: Under today's law it's nil.

MR. MORRIS: That's what I thought.

(Laughter.)

MR. MORRIS: That's what I thought I've heard you say.

PRESIDING MEMBER PFANNENSTIEL: May I ask a question on that, though. If we were able to fix that part, and we were able to set up an escrow account or something like that, to hold the SEP so that the financibility is more comfortable, does SEP still represent, then, a fundamental flaw, as you call it? Is that what the fundamental flaw is?

MR. MORRIS: Yes. The fundamental flaw is the --

PRESIDING MEMBER PFANNENSTIEL: Is the financibility?

MR. MORRIS: Right.

PRESIDING MEMBER PFANNENSTIEL: Now, Steve mentioned another issue that I guess I hadn't thought of, triggering prevailing wage. And then, of course, the other issue is just the calculation thereof, which we've spent most of the morning on.

Are there other SEP-specific issues then? I see that we do have others in the public who want to speak, so maybe we'll just leave it at that. And ask others who want to speak to come forward.

You're going to need a mike somewhere. Yeah, go ahead, --

ASSOCIATE MEMBER GEESMAN: Probably the podium, Rick.

MR. COUNIHAN: I'm Rick Counihan with ECOS Consulting. And today I'm representing a coalition of energy service providers who are here in California and need to comply with the RPS.

But I love your lead-in, Chairwoman, because I think that there are some other potential problems with the SEP's structure. And I'm going to suggest that the SEP structure should be replaced with something else. And I realize that you are constrained by statute, but you guys are the opinion leaders in the state. And so I'm just going to throw out a few ideas on why I think it's a problem and things that you might do.

So, we've talked about financibility and I think that's pretty clear. Greg brought up another point, which is SEPs doesn't work well in a REC regime, which we're going to move to with WREGIS, which you guys just approved a contract for. And it's just going to get very very awkward; the two don't go together very well.

A third thing is that for my clients, the ESPs, the whole SEP mechanisms doesn't work very well because it's premised on a Commission-supervised auction structure, the RFPs that we've talked about. And that doesn't work as well for ESPs, and potentially for community choice aggregators.

Finally, the SEPs process doesn't work so well for shorter term contracts below ten years. It could be modified to be more friendly, but we've had hearings at the Commission, the Public Utilities Commission, where there is some interest at doing shorter term contracts. And there is some evidence that in some cases new construction has happened with shorter term contracts.

So, for all those reasons, plus financibility, I think SEPs has a number of problems with it.

I'm going to just throw out three additional ideas on things you might consider, and then I'll shut up and sit down and hope that it's a good segue to the next, the afternoon.

In the afternoon we're going to hear Kevin Porter talk about the feed-in tariff. That's an alternative.

Another alternative is to go back to the new renewables account that you guys used to administer. There was competition between renewable generators in that; they had to bid their prices; the lowest price people got paid first. And there was a significant amount of generation that came out of that.

Here's another idea. No SEPs, no subsidy at all. Essentially what we're doing is we're taking money out of the ratepayers' pockets with the public goods charge and then we're using it to insulate them against the cost of the RPS being too high. All the money comes from ratepayers in the first place.

A number of other states with RPSs don't have a backup mechanism like this. The subsidy is you got to meet the RPS. And they pass those costs along in rates.

And finally, and then I'll shut up and sit down, alternative compliance mechanism. A number of states with RPS basically say that if the cost of renewables is above X cents per kilowatt hour, you can pay, as a load-serving entity, a utility or other, you can pay a price to the state that's equal to, you know, 5 cents a kilowatt hour, whatever they say it is, 8 cents a kilowatt hour. And that meets your compliance. And then that money is put into a fund that is used to fund new renewables.

And that's just another way to provide some ratepayer protection that the overall cost of the RPS doesn't go too high.

So, in summary, I think there are some significant problems with SEPs and the MPR process. And there are other alternatives. And I'll just plant those seeds. Thank you.

MR. ST. MARIE: What was the shorthand name of that last idea, again?

MR. COUNIHAN: It's called an

alternative compliance mechanism. So that if a utility in Massachusetts, for example, can't find renewables under, you know, I think it's 5 or 6 cents. I'm looking over here -- 5. They can pay that 5 cents a kilowatt hour times their requirement to the state, and it goes into a fund for new renewables.

And there are other states that have similar mechanisms.

MR. KNOX: I'd just like to point out that there is going to be a presentation after lunch concerning another state's experience with an RPS. Talking about the RPS program in Texas. And, in fact, the handout for that presentation, which is going to be done over the telephone, the handout is now available on the table in the lobby. Or outside the doors.

PRESIDING MEMBER PFANNENSTIEL: Are there other public speakers before we break for lunch?

MR. SMITH: Don Smith, DRA. On the question of SEPs, the main or the original argument against it was it's not financible. And yet the main alternative has been tradeable RECs which aren't financible either, and are far more volatile than SEPs. So I don't see that as a solution.

PRESIDING MEMBER PFANNENSTIEL: Thank you. If nobody else, we're going to break for an hour for lunch. So we'll be back here at ten of one.

(Whereupon, at 11:49 a.m,. the workshop was adjourned, to reconvene at 12:50 p.m., this same day.)

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AFTERNOON SESSION

1:02 p.m.

PRESIDING MEMBER PFANNENSTIEL: We have another two panels that we would like to hear from yet today. So, Bill, how are we proceeding?

MR. KNOX: Well, we've got, as you say, we've got two more panels, Chairman. And the first one's on contract failure and streamlining bilateral contracts. And we have four presentations followed by a panel. And then public comment.

And then we have the final subject area, we have two presentations followed by a panel and public comment.

So, I think what we want to do now is to move into the next presentation. And this next one is Kevin Porter of Exeter Associates, Incorporated. And it's an overview of European feed-in tariffs.

Kevin actually has two presentations in a row, but I'm going to queue him up for this first one; and then when he's done with the first one, I'll queue him up for the second.

MR. PORTER: All right, thank you for

having me here today, Commissioners, and the rest of the audience. I'll give some quick introductory remarks on feed-in tariffs.

Basically the thought I had in putting this together is not so much for the 20 percent RPS requirement by 2010, but if California decides to do a 33 percent target say by 2020, is there a different approach that would be necessary, or perhaps desirable.

So, in other words, rather than having annual solicitations, should the Commission consider requiring IOUs to buy renewable energy offered at or below the MPR. And that kind of an approach would be at least similar in concept to the feed-in tariffs that's in place in various European countries.

So, while people probably have a kind of a common perception of what feed-in tariffs are, they actually differ some by countries, and it depends a lot on the policy design. Just like RPS policies depend a lot on policy design from state to state.

But, in general, feed-in tariffs can be characterized by a specific price sort of named in advance, paid by electricity companies for a period of some time to renewable energy generators.

Those costs are paid by load-serving entities and passed on to customers as a premium. The price and term of these often differ by technologies, we'll see as I go through the presentation.

And while typically people see feed-in tariffs as a fixed price, in some cases they may consist of a spot price with an environmental bonus or a fixed price above that spot price.

This particular eye chart, if you will, to test your vision, is sort of a quick look at what countries have feed-in tariffs. And loosely what are kind of some of the advantages and disadvantages of feed-in tariffs.

One nice thing is that they can be designed to support, if you will, mid to longer term technologies on the commercialization curve, such as solar, for example. They may be tailored to recognize different market conditions, such as encouraging development of less desirable sites, moving renewables into the spot market, encouraging repowering.

They're probably most known for really

jump-starting a market for different types of renewable technologies. Common example, Germany with wind. Germany is now the world's leading country in terms of installed wind capacity, and that's a large part due to their feed-in tariff.

And because of the longer term nature of their price and the conditions they can offer some investment security and some market stability.

Clearly if you offer a fixed, particularly above-market price for a long period of time there is a risk of overfunding, especially if you don't account for the cost reductions in learning curves over time. And if they are constantly changed, or constantly amended, then that stability that I spoke of earlier may be just an illusion.

So here are a few examples, probably the more well known examples. Denmark is the example of that lack of stability that I was talking about earlier. They developed their wind industry very quickly over the late '80s and early '90s by offering a feed-in tariff of the spot market price plus a subsidy for 20 years.

And after a certain point of time their view was they had a lot of individual wind turbines around the country, but were quickly becoming sort of outdated on the technology curve. So they changed their incentive to lower their feed-in tariff and to offer a subsidy of 1.6 eurocents per kilowatt hour if a decommissioned, or if a wind turbine elsewhere in the country is decommissioned.

So that maximum price went from 8.1 to 6.4. And as a result the wind market largely has dried up in Denmark. And, in fact, some of the companies that got started in Denmark have moved their operations to other countries.

Now, they have feed-in tariffs for other technologies, as well. I note this for biomass; it's more of a preference for smaller sized projects.

For Germany, basically I mentioned about the fixed rates and passing along the cost along to the customers. The rate of the payment depends on when the plant goes online, so the tariff is decreased annually at a 1 to 5 percent rate. It's a 20-year tariff unless it's for hydro, and then those provisions are different.

The smaller capacity projects will receive a higher payment, so, for example, for biomass you'll see the numbers here that for the really small ones they get a much higher payment than the larger projects, say at over 20 megawatts, and then there's a bonus if CHP or newer technologies are used.

As I mentioned earlier Germany used their feed-in tariffs to really accelerate their wind industry. They're now in the position of feeling like they've used up most of their offshore sites, so they are now trying to encourage development of offshore sites. So there are some of the numbers for the onshore wind.

Note that for siting and planning purposes if the wind projects do not exceed the 60 percent of what is considered in their planning materials, then they are no longer eligible for the feed-in tariff. So there is some sort of, you must make do on what you say you're going to do.

On the offshore, the tariff for the first 12 years is 9.1 eurocents. Drops down to 6.2. But for deeper water facilities then that tariff can be extended beyond 12 years. And there's some more numbers for some of the other technologies. In the interests of time I won't go through this in any great detail. I'll just note that Germany has made a very conscious effort to really develop their solar industry, as well, too. And now they are the, I believe, the leading country in terms of solar capacity, as well.

Spain is interesting in that they are now trying to move, they offered a fixed feed-in tariff for awhile. They are now trying to move their renewable technologies into participating into the spot market. So, for wind right now, right in the midst of this transmission, there is sort of the fixed tariff that's at annually, that's the first one at 7.2. For bilateral sales, you'll see that's also set at what's called the average reference tariff that's set annually and de-escalates over time.

And then there's the market sales option. And if you participate in the spot market then you not only get the spot market price, but you also get a subsidy over and above that.

Spain also has made a decision to really accelerate their solar industry, so you'll see that these prices here are quite high for solar technology. And that for solar thermal, for the first 200 megawatts they offer 21 eurocents for 25 years and 17 eurocents after that.

If you wonder what this is in terms of U.S. cents at least as of Friday of last week, if you multiply these numbers by 1.3, which is a little bit high, but it'll get you there.

So you can see for these solar payments that Germany and Spain are quite serious about moving their solar industry along.

I'm sure the question comes up as to what sort of the impact of feed-in tariffs on end use electricity prices, and I can't find a pointer here at the moment, but if you see the yellow bar, which is like the, at least for Denmark it's the fourth one down, and for Germany it's the second one down. That gives you at least some semblance of what the overall impact on end use prices are. These numbers are from the European Commission.

And then here again here are the direct numbers between 4 and 5 percent for Germany and Spain; around 15 percent for Denmark. So perhaps not as high as you might think.

I was asked to sort of contemplate what similarities and differences are between the old standard offer number 4 and feed-in tariffs. This is kind of my rough off-the-cuff sort of comparison. Probably others who are more familiar with standard offer 4 days than I can probably add or subtract from this list.

But similarities are certainly a fixed price for a sustained period of time. And that's a fairly streamlined process. You have an offer price; you go in and sign a contract; and off you go.

The differences is that, as I was pointing out in the individual country examples, feed-in tariffs are often differentiated not only by technology, but in terms of what exactly it is you're trying to encourage, whether it's repowering, encouraging deep offwater offshore wind technology. And the price of feed-in tariffs in these countries may be lowered over time, rather than held constant.

So, some questions to think about. If you have this kind of feed-in tariff in place for a post-20 percent RPS world, should one come to be, what, you know, this kind of builds on the discussion this morning, then what happens with SEPs? Is this something that you still want to have?

Should MPR not be sort of the all-in sort of MPR, but should differentiate by technology, sort of borrowing from the feed-in tariffs of the individual European countries. Should there continue to be this time-of-delivery element.

Spain has some bonuses or adders for good grid behavior. So obvious example there would be low voltage ride-through for wind. And clearly, what's the role of legislation. Is that something that we need to think about, as well, too.

And that's what I have.

MR. KNOX: Well, I don't think I'll introduce Kevin again. I think he's still from Exeter Associates, as far as I know.

(Laughter.)

MR. KNOX: Right, Kevin? But he does have another presentation, which I'll load up here.

We'll go right from feed-in tariffs into contract failure, which is, in part, a summary of work that's been put together in a Commission publication, as well. There you go.

MR. PORTER: Thanks. All right, we put this together in part because this was a theme that came out of the workshop that was held July

6th, and there were some questions that were raised about the contract failure report that was a contract report issued by the Commission earlier this year.

So this is the building a margin of safety report. And it was based on research on the historical experience in California within the IOU service territory. So QFs contracts, the CEC incentive options, sort of early RPS contracting, as well as a survey of other North American utilities and their contracting efforts; government renewable energy contract incentives options in Europe and the eastern states. So there's a sample size of over 21,000 megawatts.

So basically the report found there's lot of contract failure, and a lot of causes. Siting issues; capital costs that increase over time; financing difficulties; transmission difficulties. Issues that I think many in this room are probably well familiar with.

This chart here shows the contract failure rate for 3000 megawatts of North American utility renewables. Here it is in California. The experience is still pretty early yet, but nonetheless we're seeing some evidence, at least, of possible contract failure in some cases.

So, can this be reduced. Yes, but not easily. Project finance clauses may make mitigation really difficult. It may be hard for developers to want to spend money until they have a power purchase agreement in hand, and in place.

As was mentioned at the July 6th workshop, you know, renewables are still very much an emerging technology. And while the industry is maturing there's still a lot of risks that are involved, as well as siting and permitting risks.

And the tradeoffs here are quite severe. It was suggested that maybe we limit bidders to established developers. However, you may lose good projects from smaller companies, however there is a widespread consolidation trend. So this may kind of work itself out anyway.

You can raise credit requirements in development stage out of impact of increased costs, but that may also frighten away smaller developers. You can ask utilities to do more due diligence which I'm sure they are doing. But it is an expensive and time-consuming process.

If you want to encourage more emerging technologies, and these are very much emerging technologies in most cases, financing, equipment supply, these are all issues that come up. And, you know, the fact of the matter is that if you take these actions they may have an effect of restricting competition which may kind of work at cross-odds or cross-purposes with what is trying to do with your RPS program here.

So what can the CEC and the CPUC do? They can be a champion for contracts to assist projects in permits and so on. They can require an over contracting margin. There may be more explicit penalties for RPS noncompliance because of contract failure. There may be mitigation techniques to explore, but you realize that there are tradeoffs with all these techniques.

More detail about the project viability in the CPUC submissions. Or abandon the RPS -- process you have in place now, and put in something more streamlined. Perhaps the feed-in tariff that I just talked about. And I'm sure there are other ideas, as well.

And that's what I have, thank you.

MR. KNOX: Thank you, Kevin, for two presentations. Appreciate it.

Our next presenters are actually two.

We have Diane Fellman joining us by telephone; we have Mark Bruce who is going to give a brief presentation about the renewable energy experience in Texas in the last few years.

But before Mark begins his talk Diane is going to give a little bit of an introduction here.

MS. FELLMAN: Good afternoon. My name is Diane Fellman, and I am the Director of Regulatory Affairs for FPL Energy in California. And joining us today on the phone -- Mark, are you there?

MR. BRUCE: I am, can you hear me?

MS. FELLMAN: Perfectly. You're this disembodied voice in a room full of people. We have Commissioner Pfannenstiel and Commissioner Geesman with their Advisors. And representing the PUC we have Commissioner Bohn's Office through Steve St. Marie. And we're sitting around at able here. So I'll just kind of guide you through this, Mark, but I just wanted to say that I'm proud to announce that, it's in Mark's slide presentation, but I have to say it, too, Mark.

That FPL Energy, as of last week, has become the world's largest owner of renewable resources in the world. And in California we are proud to say that we're the largest owner of renewable resources here. But we do have a problem that Texas just passed us in wind development. And Mark's going to explain why.

So, I'll turn it over to you, Mark. He's my colleague; he is Director of Regulatory and Market Affairs in Texas.

And, Mark, you just need to signal to Bill when you want the slide changed. So I'll turn it over to you now.

MR. BRUCE: Great, thank you very much, Diane. I appreciate the opportunity that we've been afforded to go through this with you guys this afternoon.

Do you want to go ahead and flip over to the first slide. I provided just a brief overview of FPL and our position across the states. So, I'm sure you guys are familiar with FPL's position in California and out on the west coast.

One of the things I'd like to highlight, though, is that we are active in virtually every market in North America, and more interestingly and specifically we are active in renewable energy projects in virtually every market, whether that's run-of-the-river hydro in the New England ISO, or offshore wind in the New York ISO, or traditional wind or solar or geothermal everywhere from the Dakotas through the STP down in -- and out to the west coast.

And all of that really is to say that over the past several years we'd like to think, anyway, that we have really developed a pretty broad view of what is working and what is not working, whether in terms of state regulations, tax incentives, market structures. We've kind of seen it all at this point. And we're definitely finding market models and regulatory structures that we like better than others.

And you see that reflected in the choices that we've made over the past year, two years, and the choices we're going to make in the near future, about where we invest our dollars in new capacity, as a growing company.

And I would note that Texas has been a place where we've installed a lot. And in fact, FPL Energy is the prime driver behind Texas eclipsing California in terms of installed wind capacity with the more than 1200 megawatts that we've put in in the past six years. And we're going to add a few hundred megawatts more still this year. And we will add several hundred megawatts more in Texas next year. And we are looking at development opportunities in Texas in 2008 and beyond.

On the next slide I kind of explain why that is. And that's because Texas, number one, is a business-friendly environment, just the tax regimes are reasonable, it makes sense. The host communities, particularly in west Texas, really like having our projects there.

But beyond those sort of business basics, the energy market in ERCOT is functional. You know, we entered that market in 1999 by acquiring existing projects or projects under construction.

Since that time we have built several of our own from the ground up. And we started doing this with these long-term power purchase agreements. And the ERCOT market supports that bilateral structure. But the balancing energy market in today's zonal market design in ERCOT, which is similar to California's, as well as in tomorrow's nodal environment in ERCOT, which will be similar to the L&P environment that

California's transitioning to, as well.

The real-time energy market supports merchant wind, big facilities, 150 and 200 megawatts at a whack, without a PPA. Now, there's not a lot of companies admittedly that are willing and able to sustain the development risk of constructing $150- to $250-million plants without a PPA in place. But we do it and we do it successfully where the rules are right, where the market structures are right.

And part of that in Texas is the generation siting regime; it's very very simple. In fact, for a wind facility in Texas, the only certificate we need is a certificate of compliance from the county in which the facility is located, that we are complying with the county's zoning ordinance. That's it. We don't need air permits, water permits, generating siting permits, none of that.

The open access environment is also a key to success in Texas. The restructuring bill from 1999, Senate Bill 7, made the utilities unbundle their transmission companies from the generation companies from the retail outfits. Those independent transcos now work very closely with the ERCOT ISO in a centralizing planning effort. We've broken the state up, the ERCOT region up into four regions.

And we practice regional planning. And true open access, and true collaborative regional planning has made interconnection so simple and so easy. It's still a time-consuming process; it's still an expensive process; it's still a contentious process. But it's getting stuff built. And not just wind, but solar and biomass and landfill gas, as well as a big boom in combined cycle generation. And it looks like we're about to go through a big boom in new coal generation, as well, in Texas. So, it's a regime that's friendly and technology neutral.

And then finally, you know, as the next slide shows, ERCOT has an excellent wind resource. I don't really need to go into a lot of detail about that, except that to note that, you know, the wind is really really strong in the north and the west, and way out west. And obviously these areas are far from load centers.

Which is why, in the next slide I'll tell you that it's not all roses in Texas. Actually should probably go to the next slide that says it's not all roses in Texas. We have inadequate transmission, particularly in the west, where we're in remote regions. There's a huge disconnect, as I'm sure you are all aware, between the amount of time, which is very limited, that it takes us to build windfarms, and the amount of time that it takes to plan transmission, to permit that transmission, and to get it built and into commercial service.

The local area upgrades in west Texas are very expensive because, you know, obviously there's great distances that you have to cover. And even more than that, if you can skip to the next slide that shows that map of ERCOT, you can see that the west does not have a lot of high voltage wire. The red lines that you see are the high voltage network, the 345 kV network. And obviously it's concentrated around the load centers in the Houston area, the Dallas area, and then up and down the I-35 backbone between San Antonio, Austin, Corpus Christi. But out in west Texas there's not a lot of big wire.

And we have so much wind generation coming on in the west now, and so little native load, all the electrons want to flow to Dallas, across that wire from the west to what we call the north zone. And at those constraints are binding. And it's going to require some big fixes and some expensive fixes to address that.

And so, you know, how that gets paid for, over what period of time, who builds it, are all kind of the next big issues in front of us.

If you could back up to the previous slide, I'll just mention briefly that the renewable energy market and credit market in Texas is not really what we would like it to be. We think early banking flooded that market, depressed the prices. There's been so much capacity come online that it's depressing the prices.

And it's not such a big deal for wind, as I'll talk about in a few minutes. You know, when we were, I guess -- let me back up a second -- it's not such a big deal for wind because, as I mentioned, if you got the right kind of energy market, if you can support real-time pricing, you know, wind is going to build kind of regardless of the renewable energy credit market. In a market where your fuel cost is zero, but the predominant energy price is set by fossil generation, wind is going to run and displace fossil if the transmission system allows it.

So we're okay with that. But who that hurts really is solar and the smaller projects. We saw all-time highs for RECs in Texas about three years ago in the $17, $18 range. In Texas one renewable energy credit is equal to 1 megawatt hour production. Today those same RECs are trading for $5.

So, on a per-megawatt-hour basis, obviously for the smaller projects that big shift in REC pricing really hurts a more significant percentage of the overall revenue stream for the project.

And then finally I'll just mention that NIMBY-ism is becoming an issue in Texas; and that's largely because of the first bullet on that slide. Because of the inadequate transmission in the west, developers are creeping closer and closer to the load centers. As they do that, we're entering a different type of community dynamic. And one which, honestly, is not as excited about gazing at the sunset and seeing wind turbines in the way.

So that's going to become a bigger and bigger issue, if we don't address the transmission.

Let's skip back past the map slide to the slide titled, competitive renewable energy zones. And this is the next big thing in the Texas regulatory structure. This concept came about through Senate Bill 20 in 2005; we are just now implementing this by rule at the Public Utilities Commission of Texas.

In fact, the proposed rule I'll talk about today, only came out this past Wednesday. So it's very fresh. The idea of these renewable energy zones or a CREZ, as I'll call it in this presentation, is this concept is designed to move system planning out ahead of renewable energy development.

Because it's possible, like in FPL Energy's case, for example, we can go out and identify a resource, identify the landowners, execute land-lease agreements and sign the interconnection agreement for the facility. Get that facility built and online and ready to rumble before the utility can even get a permit to build the transmission. And then we still have to let them go through right-of-way acquisition, construction, testing and getting it online. So the disconnect is really huge.

And what we want to do here is utilize ERCOT as an independent agent to, number one, assess the wind resource; number two, assess the areas where it makes sense to have big blocks of renewable energy. And we're looking at these CREZs in 1000 megawatts of installed capacity increments, so we are thinking pretty big about this.

Then with centralized planning, utilities will be able to go ahead and start looking at what it would take to interconnect 1000 megawatts of wind. And as we go through this process and illustrate how the CREZs work, you'll see how ultimately what we're looking to do is really crunch about 18 months out of the timeline for building high voltage transmission specifically to serve renewable energy.

On the next slide I'm going to talk about how that works. What the Commission is proposing is a biannual contested case proceeding to designate these CREZs. ERCOT would come in in December of each even-numbered year, starting this year, and would recommend particular zones to be competitive renewable energy zones. And they would do this based on a study of the renewable production potential which they just completed that. They hired AWS True Wind as the vendor for that study, and it's in now.

They will look at whose in the interconnection queue, whether that's feasibility studies, stability studies, interconnection requests and whatever process it is. And also they invite developers to come in and sit down with ERCOT confidentially. Because it's not a state agency, not subject to open records requirements.

We can visit with them in confidence, and we can point specifically on the map and say, look, this is where we want to build. This is where we know the resource is good. This is where we already have talked to landowners. This is where, frankly, we've already got bulldozers onsite. We can tell them things that we would never share in a room with other developers.

ERCOT can gather all that data. They can aggregate it up, as I'll show you on some maps at the end of this presentation, and then share that publicly so people can see where is the interest, what are the developers going to be.

Because the big fear, whether that's from the industrial consumers in Texas, or the retail providers who've put a piece of this program through the REC program, or honestly the Legislature, is going to hear it from constituents who ultimately pay for these transmission additions, nobody wants to build a $150 million transmission line to nowhere.

So we want to be sure the developers have demonstrated some degree of financial commitment to building the project. So that when the infrastructure gets there, there's a renewable energy project on the other end of the line to meet them. And we get these tie-lines hooked up.

And it's this centralized planning process that is really becoming the arbiter of the risk that's hanging out in the air between the parties that has been, honestly, stifling development. You wouldn't think it, looking at the numbers of capacity that's gone in in Texas, but the fact of the matter is that all of us, FPL and PPM and AES, everybody's building out there, we're cherry-picking the sites right on top of the 345 kV backbone. Nobody's building anything remote, nobody's gambling on transmission again.

The entities that got burned in McCamey (phonetic) are not going to get burned twice. And so that's why this is so critical because the sweet spots are becoming in short supply.

A little bit further down on the next slide, number 10, a couple of great features of this CREZ rule that I'll just touch on is, number one, it addresses the piling on phenomenon where, again, because everybody's looking for the sweet spot close to existing transmission, once a developer puts a project in, everybody else wants to pile on. You end up with transmission congestion. That ends up adding cost to the system. You end up having to build more wire than you originally intended.

So there are features in this rule that attempt to address that by addressing specifically how you plan for nonrenewable generation that wants to get on the same wires; or how you plan for renewable generation that wants to come into the zones after the fact.

And then finally, it's important, even as a developer we recognize that the utilities involved in transmission planning and construction and maintenance and operation have got to have a stable regulatory environment. They have to have reasonable assurance of cost recovery, of prudent expenditures to complete there projects.

And the state law, Senate Bill 20, did a great job of saying, you know, if the utilities are ordered by the Commission to build these projects, if these projects clearly meet the state's renewable portfolio standard requirement, then they are deemed useful, which is a criteria for cost recovery in the Texas PUC rules.

So, you kind of cover that hurdle of need that you have to prove for these facilities. And that gives a utility some reasonable assurance that their prudent costs are going to be recovered.

And then, again, finally the developers have got to pony up financial commitment to prove that they're going to be there. And so everybody's risk is sort of shared all the way around the project.

And on the next slide you should be looking at a map of ERCOT. I apologize if it's not really really legible as you're looking at that. But this is the original map that ERCOT produced after they had looked at their wind resources; after they had looked at the transmission grid and where it might make sense to interconnect. These were the areas of interest, trying to narrow down the scope of where we particularly want a study.

On the next slide you'll see, after they talked with the wind developers, in the pink you have areas of where there was one developer that said we want to be up here; in the blue, you have areas where there were multiple developers saying that we're looking at these areas.

So, again, you can see that like in that zone 12, zone 10, zone 6, zone 11. There's a lot of interest in there. And those overlap with areas where ERCOT already identified this might make sense. So these ar going to be the key areas that the Commission is going to look at in terms of the first competitive renewable energy zones to get developed.

And then on the next slide, and the one after that, you just see that we've developed, based on the AWS True Wind study, net capacity factor curves for each of the zones. So, again, when the Commission is looking at this they're going to be able to judge the potential annual production of renewable energy, the net capacity factor of that.

And so when they approve these things, when they start approving costs, when they start approving plans to serve these zones, then the Commission is really going to have an idea of what kind of value, what kind of energy potential they're delivering to the grid when they do this.

And all of this is designed, at the end of the day, to balance the cost and the benefits of this particular type of technology.

That's really all that I have for you guys today; and later in the discussion I'd be happy to answer any specific questions you might have.

MR. KNOX: Thank you very much, Mark, for preparing this presentation for us on such short notice. We really appreciate it.

Now, we'll go ahead, and the fourth and last presentation of this subject area is Roger Johnson of the Energy Commission. And he's going to be speaking about permitting assistance during the 2001 energy crisis.

MR. JOHNSON: Good afternoon, Commissioners and members of the audience. My name's Roger Johnson. I manage the Siting and Compliance Office here at the Energy Commission.

I've been asked to discuss with you today some of the permitting assistance that occurred during the energy emergency. It seems like some activities that we developed and used in those days might be helpful today to help projects go to completion.

Just a little bit of background of the 2001 energy emergency for those of you who were here who remember power plant outages and electricity and natural gas prices increased dramatically in 2000 and 2001. Some generators refused to sell electricity to California because of a lack of a credit-worthy buyer.

The Energy Commission forecasted a 5000 megawatt deficiency for the summer of 2001 if we had a hot one-in-ten summer. And the Governor declared an energy emergency and issued executive orders to address the emergency.

The Governor also signed AB-970 that contained measures to reduce demand and increase energy efficiency, conservation and generation towards this 5000 megawatt goal.

Some of the agency efforts in

California. The Governor created an emergency energy team of agency secretaries and department directors to implement and monitor the emergency situation.

This team was led by the cabinet secretary, at that time Susan Kennedy. And it was made up of members of all the secretaries, Cal-EPA, Resources Agency, directors of Department of Resources, the head of ARB, the Energy Commission director. So these were high-level members of this team that were able to work together and get things done when issues arose.

The Governor also appointed a clean energy green team to oversee local permitting and construction process for small renewable and peaking power plants. This green team had a few staff. I think they had offices with the -- I can't remember now, but the green team coordinated with the 14 Cal-EPA regional permit assistance centers in California to provide developers of emergency power plants with permitting and construction assistance.

This was a very timely joint effort by the green team and the assistance centers. Those permit assistance centers no longer exist in

California due to budget problems. And now that whole assistance effort is a website that a developer can go to when they come to California. They can look up their business on that website, and it gives them a list of -- they tell it what city and what county, and it gives them a list of all of the permits they have to obtain.

And if you email the site you get a message back saying, unfortunately there's no one here to answer your email. So, it's helpful, but it's more intimidating than it is helpful, I think, if you go look at the site.

The Energy Commission developed the emergency 21-day permitting process and the four-month peaker permitting process. We also expedited our amendments to existing facilities.

The Energy Commission developed and coordinated an interagency project tracking system. This was something that turned out to be very helpful. But it was just put together with a series of Excel spreadsheets. We had trackers, you know, contacting project developers, getting updated information, doing weekly calls, and putting together a list of projects and issues that each project was facing.

We would have conference calls weekly; then it became every two weeks; and then finally once a month. And now they don't have them anymore. But this was trying to get these projects through permitting and then into construction; and through the construction. So that turned out to be a good exercise.

The green team. What worked well. The green team focused on facilitating the completion of projects below Energy Commission permitting authority, which is 50 megawatts thermal. Those projects that had existing summer reliability contracts with the Independent System Operator. So really focused in on those projects.

The green team permit assistance centers offered valuable assistance in helping projects resolve permitting issues and barriers with local agencies. The green team didn't have any experience, though, with power plants. Most businesses coming into California are dry cleaners, other kinds of industries besides power plants.

So we met with the green team. We brought all the office managers in from their 13 regional offices, and we explained the power plant permitting process. And explained what they could do to provide assistance to these developers.

What could have helped the green team? it looks like establishing a separate process or a group of people within the contracting agency at that time would have been DWR. Designated to focus only on small renewable generating facilities, and provide direct feedback and negotiations from the beginning of the process could have helped those projects.

Using a separate group of people focused on small projects, to assist the project developer in dealing with transmission issues and associated costs, and setting up methods to share costs with other projects using the same transmission facilities. And then amortize interconnection costs might have resulted in a greater number of successful renewable projects.

These projects tended to be small and essentially developers were inexperienced with permitting in California. And it was a real frustration for them to try to go through all the different permitting processes, especially the interconnection that very difficult.

The Energy Commission, what worked well

for us. Well, the siting office, my office, my phone, served as the clearinghouse for project developer inquiries. We had an enormous number of inquiries. People wanting to know who do I talk to about a project. And then directing them to that right agency.

We had information workshops for project developers. We had a northern California workshop and a southern California workshop where we invited all the developers that were wanting to participate in this emergency permitting. We explained the permitting process; gave them information that they needed; and provided contact information.

We set up a website bulletin board for project developers. It turned out pretty useful. It was like a Craig's List for energy equipment. You know, we had turbines on there, we had people looking for HRSGs, that type of thing. It was interesting.

The Energy Commission website, we had developer and local agency assistance guides online. They're still there today. We have an energy aware planning guide for energy facilities. We developed this for local agencies. It goes through the whole permitting process for thermal power plants. And it gives them an in-depth look at what to look for for permitting power plants and what kind of issues they should be looking to address.

And we also have our energy facility licensing process developer's guide of practices and procedures. This is just a fairly detailed discussion for developers on power plant permitting in California.

What could have helped? I think a toll free hotline call center would have helped me a lot. Something where people could have called and gotten the information they needed.

Project tracking, what worked well. The project tracking provided regular status reports on projects in permitting and construction. We developed these reports; once a month we presented them to the energy action team over in the Governor's Office. So we aggregated all the reports every month and kept track of what was coming on. We had confidence levels for each of the projects and we tracked them online.

The tracking group included staff from the resource and the infrastructure agencies, so we had folks from ARB and DWR, General Services, all the agencies that might have something to do with the permitting.

Roadblocks to projects were identified early and agencies were contacted to resolve the issues. That's probably the biggest value of this whole effort was having this interagency group that could identify an issue and then either take it down the chain from the energy action team or the secretary told people to get the problem fixed; or take it up for people who knew what the problems were.

Interagency cooperation greatly improved between the agencies and remains high today. Another value from that exercise.

Project tracking, what could have helped. I think conference calls could have been improved by using the WebEx file sharing features that we have today. Back in those days it was just a conference call, and we, you know, just took notes and traded files using email.

Tracking could have been more efficient using email rather than phone calls. I think now everybody's more email-abled. I think with the phone call you played a lot of phone-tag trying to get information from the projects.

And a tracking software application would have been an improvement over the ExCel spreadsheets that were submitted by the trackers for report preparation. And currently we're putting together such a tracking software that we're getting ready to use again to track current development in California, which could be useful to this effort, as well, for renewables.

And if there's any information that you'd like I have my information number information here.

MR. KNOX: Thank you, Roger, for that interesting presentation.

We're going to move right on into a panel discussion around the roundtable at this point, moderated by Kevin Porter.

MR. PORTER: All right, thank you, Bill. We're going to be focusing on questions 6 through 9 of the notice of Committee workshop. So, if you don't have that, that's fine, I will -- at least I'll go through this in order and I will give you the cryptic, the main point of the question. And then we'll just see where the discussion goes from there.

And, of course, Commissioners and Advisors, feel free to chime in at any time. We'll go till probably about five or ten of three, and then we'll see if there's any public comments.

I would ask people around the roundtable, at least for the first time, to identify themselves and their organization for anyone who may be participating on the phone.

So, question 6 notes that there's a lack of close coordination between transmission and project development, unfamiliarity with detailed permitting procedures, and incomplete communication could result in projects not coming online by 2010. What steps are utilities taking to minimize contract failure and delay?

Given the nature of the question, let's start with our utility representatives first.

MR. KUGA: All right, I'll go ahead and start. I would say our experience for the last several years is that we have had very little contract, if any, I can't recall any contract failures.

I think what we find are struggles in terms of getting concept to contract to project. And that stems from financing issues as well as permitting and development issues.

I would say we can ask developers from their standpoint in terms of whether the contracting process can improve. But I think from our experience the project struggles have been related to broader issues in terms of financing or transmission availability permitting type issues.

In terms of what we can do to minimize future potential for failures, I think we've talked about some of that this morning, as well as it was discussed at the July 6th workshop. I think there are steps that are being undertaken with the joint agencies, as well as with the ISO and the utilities and the market participants in terms of closer coordination for transmission development.

And I think the process has been more smooth in terms of making sure that critical transmission projects are being identified that would help facilitate development of bringing more remotely located resources to load.

I would say from the standpoint of performance, I believe there was a lot of discussion at the last workshop related to credit standards and performance standards. Those, we believe, are really critical in terms of insuring that projects are committed to moving forward an that developers are fully engaged and have skin in the game in terms of moving forward with projects.

What we want to avoid, and we've seen some of this, just a few instances in my experience, is that people may want to shop around for better contract even though they may have an existing contract. That can create some challenges in terms of contract failure.

We talked this morning briefly about the TOD and the implications of SEP payment, you know, the difference between an Edison payment for a project like solar versus PG&E, relative to SEP requirements, can impact that.

In terms of state and federal tax credits, that seems to be a key issue. The financing and project development and pricing of contracts have this overhang of the uncertainty of the renewals of the production tax credits and the ITC credits at the federal level. And those seem to have implications in terms of ultimately what the payments will be, as well as the financing. And that we need to accommodate certain provisions for the renewal of them, or the nonrenewal of them from a contracting provision.

So being aware of these, and also being supportive of the continuation of these, I think will help promote contract success and minimize failures.

Finally, I think I already mentioned this. The posting requirements, I think, are really critical. What we see is the performance requirements in terms of achieving milestones identified in at least our contracts were there are certain identified milestones and incrementally higher posting requirements. All move towards greater success in the project development and actually bringing projects to fruition.

MR. HEMPHILL: I'm Stu Hemphill from Southern California Edison. I also can't think of a single contract failure we've had, but we have had some challenges. And virtually all of them relate to transmission.

I think the most difficult component is getting interconnection in areas where we have congestion. And over a period of time, and it's completely understandable, the Cal-ISO has put a policy together where they do not want to have to make exceptions for individual generators.

And so they've had sort of a blanket no-new-congestion policy that they've implemented. We've worked with the ISO. We've been trying to see if we can get an exception made for renewable developers in meeting our goals.

The interconnection queue, itself, is problematic, as some entities are able to remain with priority in the queue, even when new transmission is being built. So, that creates a variety of different problems.

But one of the ways that we've tried to deal with it was I gave the chief negotiator a call and tried to see if I could do a bilateral agreement just to get them into a contract. Because a lot of the -- well, many of the megawatts that were in the queue were not contracted to anybody. And so they're holding a space in the queue without a contract.

Ultimately they did the right thing and got themselves out of the queue. That also creates problems because a ton of analysis and engineering has been done assuming that they will have a project there. So a lot of the analysis from an engineering standpoint has to be redone when somebody's removed from a queue. It's a very very complex process, and one where we'd greatly appreciate any help and support to get new renewables interconnected.

MR. FRANK: Good afternoon; my name is Dan Frank with San Diego Gas and Electric. I pretty much echo the same that Roy and Stu have mentioned.

We're dealing with the same challenges and we haven't really, to my knowledge, had a contract failure based on, you know, the lack of transmission. The ones that I recall that we've had problems with have been more with the developer getting financing and being able to move forward, meeting the milestones we have in the contracts.

But some of the challenges that we see with some of the newer contracts we have signed are the timing of when the transmission is scheduled to be built. And what we try to do is build contingencies in our contract to accommodate the timing of those things.

And we kind of work closely with the different study groups in the state to make sure that things are moving forward with the transmission development and that sort of thing that do affect our contracts.

What we're concerned about is if the transmission lines don't get built on the times that we contemplated in our contracts, it kind of has a rippling effect where if it's delayed it can affect the pricing of the contract because of the economics that were put into the bid could change because the price of the project could get more expensive over delaying it due to, you know, increased costs for construction or materials and that sort of thing.

It has an impact, as Roy mentioned earlier, about production tax credits and ITCs. Those are also factored in the offer prices that we have. So, we are concerned that a lot of the contracts that we do sign are contingent on transmission getting built in a timely fashion that won't impact having to go back and possibly reopen and renegotiate the contracts.

So what we try to do is stay on top of each contract that we have with the milestones we have in the contract, making sure that hopefully things are moving forward and moving in the right direction.

MR. KELLY: This is Steve Kelly with IEP. I guess I'd like to respond to that a little bit because what I heard from the utilities was that everything's going fine, there isn't contract failure. And I think it's a little premature to tell that yet.

But primarily the problems tend to be around transmission. And I understand California's got some transmission constrained areas that it's not clear to me how we can implement a least-cost/best-fit methodology to select winners and losers in these bids; and have everybody transmission constrained or with no site control.

This gets into the transparency of the evaluation criteria that we talked about a little earlier. But it's amazing that all the projects that are being selected apparently, or a lot of them, are transmission constrained. And they're waiting for transmission to be built, but no transmission is being built. It's been three or four years since the RPS has been implemented. So what's going on?

I mean those are conditions that are not in the developer's control necessarily, particularly for network upgrades.

So there's a tremendous problem there, I agree. But I'm not sure that it's something that we should flippantly say it's just a lack of transmission. How are least-cost/best-fit methodologies being implemented? Who is not getting selected and are people not getting selected who are not transmission constrained?

We have not tapped into any SEP money as far as I can tell, and setting aside the discussion we had this morning about the financibility of that, let's assume it is financible. We've never tapped into any of that to get somebody who might be a little bit more expensive but have no transmission constraints.

And I don't understand how this process can be resulting in that.

The other thing that I'm hearing from a number of developers is that tremendous delay in negotiating. One of the reasons, in this market particularly, where steel, the price of steel moves around so quickly because of what's going on in Europe and China and other places, if negotiations string out for 14 months or 18 months or whatever it is, the developer's prices are fleeting them as they negotiate.

Their only recourse at that point in time in order to capture the PTC money is to take what turbines they've got and put them into Texas or someplace else where they can get them in the ground and capture the federal money.

So, one of the other things we've got to work on is expediting the negotiations once you're selected so that people can actually stand behind the price they bid. And there's a concern, at least in my mind, that that's a problem right now.

The other issue that I'd point out is I've talked about it a number of times, is with the lack of transparency and the lack of understanding about where utilities might prefer to have these resources to meet the reliability issues that Stu mentioned this morning, in addition to the RPS requirement to produce energy delivered to the grid, we get -- I think there's a delay that occurs because people are bidding projects that might not be exactly where the utilities would prefer to have them for best effect.

If we can pry open that issue a little bit I think you're going to get people planning ahead, thinking about where to put projects, investing money before they actually bid a little bit more, to try to get better sites to the utilities proposed so that they can come online quicker. And my impression is that is not happening, as well.

MR. FREEDMAN: Thanks, Matt Freedman here representing The Utility Reform Network. I think I'll echo some of the comments that the utilities made, but also point out a few other things that I think are relevant to the discussion of contract failure.

It's important to understand that two of the three utilities, PG&E and Edison, were pretty slow out of the gate in terms of contracting for new resources under the program. The PUC ordered solicitations at the end of 2002. And Edison and PG&E basically relied on existing resources for the most part. San Diego went out for a bunch of new projects, and they've actually experienced some contract failure because they've been trying to get new stuff built.

The vast majority of the megawatts under contract that we're now looking at were signed up in the last year basically. The results of the last two solicitations yielded contracts that were executed in early to mid 2005. And then there's a bunch that were executed this year, and a whole bunch more that are probably coming.

So, the issues with the other two utilities have yet to manifest themselves because those projects have online dates that are a few years out.

So you take that into account, first of all. Then you put on top of that the issue of production tax credit uncertainty which seems to be the elephant in the room here. Every single deal in California, as far as I know, is contingent on production tax credits, unless it's an investment tax credit based deal.

And right now we're in a cycle of two-year extensions at the federal level, which is just enough to create total chaos as far as I can tell. Because developers won't lock in their deals and commit real money until they have a clear path to getting that PTC. Because if the PTC expires 24 hours before your project is finished, and the risk is on your shoulders, the deal becomes uneconomic overnight.

It seems like that's basically true. No

one has ever suggested differently. The production tax credit has such a large value to the developer that it's impending expiration creates all sorts of problems.

On top of that you have transmission, if there's any transmission upgrade required, of course, we've got a big delay. Then we have equipment prices going up, specifically wind turbines. Every time we turn around we hear about new reports of turbine price increases.

So you put all those three together and it seems like it's very hard for developers to commit to prices that they can honor, because they're waiting until they have a clear path to transmission and tax credits, assuming their siting is under control, to even commit the money to lock in the turbines. If they haven't locked in the turbines for a wind project, and they wait until those hurdles have been overcome, then they want to come back and renegotiate the price, because the deal doesn't work anymore.

So these are some of the things that I've been seeing across the three utilities that have been happening. It's not necessarily anybody's fault. I think it's just a confluence of factors that are conspiring to create big problems.

And it raises the question of what are we to do. How do we get around some of these. Production tax credits issues, could we come up with a state production tax credit that would be a backstop if the federal one doesn't get extended?

Of course, the preferred outcome would be that the federal tax credit gets extended for a long period of time to create certainty. But assuming that we cannot do that in California at this time, is there a state-level backstop? Or should we have the utilities taking on the risk of production tax credit expiration? That would be one burden that would be removed from the developer's shoulders.

If a project is relying on any form of supplemental energy payments, as folks know, big uncertainty around that. What kind of award will they get? I don't think developers that need that money are going to move forward until they know exactly the award that's going to be issued by the Energy Commission.

And then we have transmission delays. And I know everybody's talked quite a bit about that. What other options do we have? Well, I don't know if it's been mentioned, but of course utility ownership is an option about which I'm not particularly excited. But I note that it does remove some of the incentives to walk away from deals that some developers might experience.

Another option would be for utilities to purchase major equipment like wind turbines in advance, and ask developers to bid on building projects with the utility's turbines, which would mean that a developer can't take the turbines and walk away if it turns out the price is better in Texas.

So I think just this timing issue is potentially going to create some issues down the road. Unless we have enough transmission in place and the tax credit situation resolved.

ASSOCIATE MEMBER GEESMAN: You recommended two particular redistributions of risk to the utility, one being PTC risk, and the other being turbine availability risk. Would your organization support the utility absorbing either one of those risks?

MR. FREEDMAN: If the deal looks appealing to us then we would.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. FREEDMAN: It all depends on whether the deal looks good. And if the deal looks bad, even with the PTC risk included, then it's probably something that we would not support.

MS. FELLMAN: Diane Fellman from FPL Energy. Mark, are you still available? Mark?

MR. BRUCE: Yes, I am here.

MS. FELLMAN: Thank you. I was going to comment on some of these risk factors that you just mentioned, Matt. Texas has the same risk factors. Equipment prices are going up; PTCs might expire.

Mark, could you comment on how Texas developers look at these risk factors and take them into account in building projects? Because I just don't think it's those risk factors that are keeping turbines out of California.

MR. BRUCE: Well, to a certain extent, I mean those definitely are risk factors that are at play in Texas and smaller developers, in particular, are more reliant on the PPA deal structure. I think, you know, one of your panelists earlier mentioned that if it takes a long time to negotiate the PPA, the terms change.

And that changes -- that's one of the ways that FPL and some of the other developers have stepped around that risk, is by not going through that process; and doing sort of a merchant model. That helps a lot.

MS. FELLMAN: Excuse me, Mark. Could you speak up a bit; it's a little bit hard to hear you in the room.

MR. BRUCE: Yes, certainly; apologies. But certainly I think probably the biggest difference is you just have completely different siting regimes between the two states.

And to the extent in California, I mean I think you can mitigate a lot of those risks if there's a way for you to, you know, do that through the siting structure. It's really all about speed; it's about taking time out of the timeline from project inception to project delivery.

MS. FELLMAN: And I would say on, from the California perspective it's not just the siting regime. Because certainly our siting here is done at the county level and this Commission is looking, the CEC is looking at guidelines that will help expedite the wind siting.

But it's also a question of contract negotiation; how the MPR fits into the timing of contract execution. And I think when we look at -- when we're, as a company, are looking at, you know, where to invest a billion dollars of capital, in what kind of projects do we have, or what kind of platforms do we have available for our projects, it's really important point that Mark made, and I'd like to underscore, is what kind of market is available.

I mean usually the conversation about renewables, sometimes it's called the green ghetto, is put into a sidebar conversation. But as Mark said in his presentation, the structure of the energy and capacity markets in any given jurisdiction are really important to us as a company. And if there's a functioning market, as we do in Texas, we are able to build projects quickly and sell into the market without having an underlying power purchase agreement because of the incentives and signals that we're getting from the market.

Now, having said that, we are a large company and we have a lot of capital. And as Mark said, there are small developers who require contracts. We went in with a contract approach. So it's not to say that contracts need to be pushed aside and there's only a market model.

As we've testified before the Public Utilities Commission and I'll state today, we believe there should be a suite of options available, one of which is a power purchase with a utility. And hopefully in the near future, not too distant future, we have a market model where we can build merchant renewables, as well.

ASSOCIATE MEMBER GEESMAN: Well, I guess I'm going to ask you, not necessarily today, but perhaps in writing, to submit something to our docket, Diane. John Seymour from your company at our July 6th workshop indicated that FPL was not, at this point, participating in any of the utility RFOs in California.

Frankly, I'm surprised that that declaration did not attract greater notice. I know it caused quite a bit of concern on the part of the Commissioners that were in the room when he said that.

I guess I'd like you to address whether you think the development of the ISO's MRTU market will afford you a realistic prospect of taking on a merchant role in California when MRTU is rolled out. And also whether the prospect, which I believe exists today, at or below the MPR, of doing bilateral transactions with the California investor-owned utilities is an attractive prospect to you.

And if neither of those two are particularly appealing, what changes in the RFO process it would take in order to entice America's largest windfarm owner into the California market.

MS. FELLMAN: We would be happy to provide those remarks. I understand that the deadline is a week from Monday. I may ask for an extension on that.

ASSOCIATE MEMBER GEESMAN: Those are usually granted.

MS. FELLMAN: Big question. And I also want to add for the record that we are also the largest owner of solar thermal generating facilities. So, we are -- and those are located in California, as everyone knows, the old Luz plants.

ASSOCIATE MEMBER GEESMAN: You can apply those same questions to solar thermal as well, then.

MS. FELLMAN: Very good. And these are very serious questions and it's something we look at internally. We'll think long and hard about how to respond. We've raised our concerns at different fora, so, Commissioner Geesman, we appreciate the opportunity to do that here, as well.

MR. PORTER: Go ahead, John.

MR. GALLOWAY: Sure, thank you. John Galloway with the Union of Concerned Scientists. I'm always intrigued by the notion that may exist that the utilities are only picking bad contracts that have lots of contingencies. And that's pretty much the menu of what's on their plate.

I mean the negotiations that the utilities are going through are inherently complicated; and, you know, I think Steven raised a really important point that the negotiation cycle has been historically taking a fairly long time to complete, which I think is a problem. Because what happens in that back-and-forth is you end up, you know, with markups, with markups, with markups on top of markups. Which then, I think, are pushing the solicitation cycle back, you know, greater than a year in some instances. And in

Edison's case we saw one drag out even further.

I think one way that that's being addressed that I can see is that the utilities are, you know, I think everybody really in this market and in this industry are going through their growing pains as the renewables become, you know, a very significant generation source in California. And we're going to increase that by adopting a policy like an RPS.

It's not to say that, you know, those growing pains are going to last forever. And I think at least since, you know, the question at hand is what steps the utilities are taking, at least what I'm seeing is that the attention is now being focused on renewables to the point where the utilities are bringing in dedicated staff to work solely on these negotiations, solely on renewables issues and compliance with the RPS. And that they're not being scattered across multiple different projects.

I think that has been a major burden over the last couple of years is that the same staff are dealing with transmission planning, with QF resources, with renewables, you know, the all-source RFOs and the whole nine yards.

So I think that, you know, I think there are improvements that can be made there, but I think the utilities are certainly taking steps in those directions. And, you know, as far as what's happening in that back-and-forth across the table, I think it's really hard to get into very many specifics about that, because I think those negotiations are inherently under wrap.

So I think what we're seeing is sort of the, you know, the problems in aggregate. You know, everybody here, I think, has pretty much raised the issue of production tax credits, wind turbine availability, steel prices. But how that actually plays out as, you know, as the utility staff sit in those contract negotiations, it does take a long time.

So, I think to the extent that we can cut corners, not cut corners, but to the extent we can bring those, you know, those cycles more into a streamlined fashion, the better. But, you know, at some point this is a complex market. And I don't think you can just do this in a day. You can't just put a contract before a developer and say, oh, great, we all agree on these terms. That hasn't happened yet in any contract I've seen to date.

So, I don't think that the utilities are necessarily focused on projects that are, you know, fitting within their least-cost/best-fit evaluation, that all have complications. But a lot of the projects that we're starting to see on the table are in areas that are transmission constrained.

So, I think the utilities are really looking at a mix of all different types of contracts across a range of prices and a range of technologies, and really looking for the least-cost and best-fit projects.

So, even though, you know, I think that moniker has come under a lot of criticism for being a black box, I think the utilities are really looking for solutions across all of those projects.

You know, getting to what is the right solution for minimizing contract failure, I think Kevin put a really good list up that looked at a number of different strategies. And I think we should be approaching a lot of them. I don't think there's one right answer. It's not 30 percent over contracting margin; it's not just increasing the utilities' annual targets; it's not just looking at permitting assistance or additional due diligence on the part of the utilities. I think it's a menu of all of those.

Again, you know, this is a fairly complex program, as is energy policy in California. And I think we really need to leave no stone unturned.

In my experience of working with the utilities is that they really are looking under every stone and looking for ways to solve these problems.

And I guess we're going to get to the support structures next, as our next question. So I have some additional comments there. Thank you.

MS. RADER: Nancy Rader, Executive Director of the California Wind Energy Association. I find myself not disagreeing with anything I've heard, and agreeing with most of it.

But when I was thinking about the question of, you know, these questions are really aimed, it should be micromanaged, the procurement and contracting process, more than we are now, I sort of took a step back and thought about the spectrum of approaches that you can take with an

RPS, both in theory and as they are being played out in states around the country.

And the spectrum on one side you have a very prescriptive RPS telling the utilities exactly what to do and very lax penalties on the other side because it's hard to impose a penalty when you've told the utilities exactly what to do.

And on the other side I think something more like Texas, which actually Mark didn't cover too much. But my understanding of the Texas RPS is that it's very light on telling the utilities and the other retailers how to meet the RPS.

And it's very clear that a penalty, a hammer is going to come down for every kilowatt hour that they're short. And so those are two, you know, those are the ends of the spectrum.

I think we're somewhere in the middle. And on the one hand our statute has some prescriptions in it, which is due in part to the fact that unlike Texas, California's retail market is not competitive. And so you have still highly regulated utilities that have recourse to the ratepayers' pockets, and therefore has to be some oversight that they're procuring renewables fairly and at least cost. And so we have the least-cost/

best-fit process, et cetera.

But at the same time the utilities have asked the PUC for a lot of flexibility in how they go about complying. And they've, to a large extent, received that flexibility.

For example, there's almost no standardization of contract terms; little transparency in the least-cost/best-fit process. And wide latitude in the procurement process.

So, because they've been given this flexibility, we think it's essential that the PUC hold them accountable for actually meeting the RPS targets on time. Which is not to say that there might not be good reasons why they may not always be able to do that, primarily that the transmission problems. But if the utilities do everything in their power to get the transmission capacity built on time, and also facilitate early interconnections through temporary interconnections, and they take action to insure that those projects actually materialize, then maybe they deserve to be released from some of the penalties that are associated with that transmission lead time.

But at the same time the utilities also

have to demonstrate that they've done everything they can to acquire the low-hanging fruit, or the projects that don't require transmission, even though, as Steven said, they might be a little bit higher cost. But if they can be built next year, you know, you better take them.

And, you know, we're not convinced that that has been done. In part because we know some of our bidders have been deterred from bidding because of the credit requirements; or their bids have been rejected because of the costs associated with some of the onerous contract terms.

And so, but, you know, to get back to the question of should we be more prescriptive in telling utilities to impose better milestones, or to have X amount of extra megawatts under contract, or all those things, I think even though CalWEA has been really advocating a lot of prescriptive things, sort of to date, I think we're now at a point where we're saying, you know, enough of that and let's just let the hammer come down and impose penalties where they are deserved.

And in so doing the utilities will get a lot smarter in shortening the negotiation process and, you know, reducing the onerousness of the contract terms, et cetera.

So, you know, I think we need to tilt a little bit towards the Texas model in terms of imposing penalties and counting on that going a long way towards making the utilities more nimble and smarter about how they go about procuring resources.

MS. FELLMAN: I was going to suggest that maybe Mark talk about the Texas --

MR. BRUCE: Without going into too much detail, I generally agree with what Nancy has said about where Texas falls in the spectrum there.

It's really quite simple that only the competitive retail areas of the state fall under the requirement of the RPS. And the way that is met is that retailers are assigned a certain number of renewable energy credits that they have to retire in April of each year for the preceding calendar year.

And that formula is arrived at basically by taking the stairstep capacity goals set by the legislation, multiplying it out by the number of megawatt hours of renewable energy production you expect in a year, and then, you know, getting your target to where you're, you know, ratcheting up the REC requirement as you're ratcheting up the capacity goals.

The penalty is real simple. For every REC you are deficient in April for the previous calendar year, you are assessed a $50 penalty. So it's basically $50 a megawatt hour, which doubles as, you know, setting a cap on the price of a REC, right. Because obviously it won't outstrip the compliance penalty.

So that's how it's done. It's purely financial. And to my knowledge, since the REC program began in January of 2002 only one retailer has ever been short.

ASSOCIATE MEMBER GEESMAN: Nancy, there was quite a bit of discussion at our July 6th workshop that the so-called Matson decision adopted by the PUC in May did precisely what you're suggesting, and made as clear as the PUC can four years ahead of the deadline, that the goals are serious and that penalties will be enforced if the program is unsuccessful in meeting the goals. Would you agree with that characterization?

MS. RADER: I hope we're not just thinking about 2010, but every year up to then, because we have annual goals that are, you know, may or may not be being met.

ASSOCIATE MEMBER GEESMAN: Well, we also have flexible compliance provisions that soften many of those annual goals.

MS. RADER: Yeah. I mean Matson said in a couple cases, I think, you know, either you do X, you don't have to do X, but if you don't do X, we will take that into consideration when we decide about penalties. And I kind of think that's the approach we need to take, is, you know, it's been suggested by various people that there's these various problems; and you can either fix those problems or if you don't make the goal, you can pay for not having done those things.

MR. MORRIS: This is Greg Morris, Green Power Institute. I certainly agree, and have said so in various filings, that as you give more flexibility to the utilities in terms of how they meet their RPS goals, the only way to make that work is if you also have the enforcement if they don't make the goals.

But because of our flexible compliance provisions we're not going to be enforcing the goal, for example 2005, until 2008. And we won't be -- you know, everything is three years behind. And moreover, we have a number of utilities that are potentially in the position where their shortfall will be greater than what is required to make them reach the maximum penalty levels. So, you know, if you're in that position you lose the incentive to try and push along.

I am not in the position of having been on either side, or any side of contract negotiations. But it certainly occurs to me, as an outside observer of that process, that anything that can be done to streamline it would be a great help.

MR. PORTER: Well, the preceding discussion confirms to me that we have a very verbal and articulate group here. Took us about 50 minutes to cover one question. So, I'm going to dispense with question 7 in the interest of time, and move on and ask that we address questions 8 and 9 combined. And ask, actually, if you could be somewhat less verbose, as we'll allow a little time for folks in the audience or on the phone to comment.

So, question 8 references the feed-in tariffs that I spoke about at the beginning of the afternoon. And asks can bilateral contracts be streamlined to achieve similar growth in renewable energy development for California. And should the CPUC require investor-owned utilities to buy any renewable energy offered at or below the MPR.

I'll ask anyone who wants to comment to address those two combined. And because I asked the utilities to go first last time, I will ask the nonutilities at the table to take their first swing at this.

Diane.

MS. FELLMAN: Yes.

(Laughter.)

MR. PORTER: That was certainly brief.

MR. FREEDMAN: Matt Freedman here. I will be less brief. As I think about the role of a feed-in tariff or just a standardized price for renewables, a number of questions come up.

It appears that the major argument in favor of a feed-in tariff is that number one, it reduces dramatically the transaction costs associated with competitive solicitations or negotiations of individualized contracts. And folks have been complaining about that adding time and money to the process. So, dispensing with that part of the equation.

The second is that it creates some kind of certainty for the developer, a price target. You can meet the target, you can build it on time, you're going to make money on your deal. And it's going to work.

So those are the two types of benefits that I see.

The downside that I'm concerned about comes on a couple of fronts. One is we, with the standardized pricing approach, we potentially lose competitive efficiencies to the extent that a producer can sell at a price below the MPR or feed-in price. All of the surplus associated with that difference goes to the seller and not to the consumer.

We have a market price referent currently in place right now. We've had one for several solicitations. And almost all, not all, but almost all the contracts have come in below that price.

If a developer knew that it would get anything up to the market price referent and the utility had to buy at that price, I don't know why any developer would bid below the market price referent. There would be no incentive, so long as you knew that you would get the price that was being advertised. I don't understand why you would bid less.

So, we're losing that opportunity to gain dollars on behalf of consumers, and potentially overpaying for renewables relative to what's needed to bring them online.

Also take into account that there are so many different renewable technologies that are playing in California that in order to make any kind of system work we would need to set many different feed-in tariff prices.

You'd need probably a wind price, a photovoltaic price, a geothermal price, a biomass price, different biogas prices and so on. This could be a complicated exercise. And this may cut against the reduction in transaction costs and the argument in favor of simplicity.

We would have to be litigating, I imagine, on an ongoing basis, the right price to pay for each of these technologies, potentially in different parts of the state. In Germany I understand they segment it by region. If we were to do the same thing here we might end up with 20 or 30 different prices across California that you'd be paying.

If you didn't want to go that way, if you just had a single price, well, then you would end up setting a price that didn't work for may technologies, and was probably too generous for other technologies. So you'd never really quite get it right.

In terms of certainty, if a feed-in tariff is based on an adder to the spot market price, as was discussed in the presentation, I'm not sure that creates the kind of pricing certainty that a developer needs if it doesn't know what it's going to be getting over the term of the deal. And so far developers have really been unwilling to build to spot prices in California.

Transmission, feed-in tariffs don't solve that problem. You still can't build a project if you don't have the ability to interconnect to the grid.

And then there's the location issue. I mean there's been discussion about can we move these projects to where the utilities want them. Can the utilities pick where it's best on the grid. Well, with a feed-in tariff there's no discretion from the utility's perspective, I suppose. The projects get built where the developers want.

So those are some of the concerns that I would have. I think it's an interesting approach, but we really need to look at it more to figure out whether it will deliver on the promises, or whether it will just set prices that nobody likes that don't get projects built as economically as we could, and create a new level of administrative complexity.

ASSOCIATE MEMBER GEESMAN: In your experience with the PRGs, how large has the delta been between the market price referent and the accepted bids?

MR. FREEDMAN: It can be quite significant.

ASSOCIATE MEMBER GEESMAN: So, on the aggregate, that's a significant number of dollars?

MR. FREEDMAN: Oh, I think it's definitely a significant number of dollars that we'd want to keep in mind.

ASSOCIATE MEMBER GEESMAN: And can you share some sense of what the magnitude of that is?

MR. FREEDMAN: Perhaps one of the utilities could offer it so i don't get myself in trouble.

ASSOCIATE MEMBER GEESMAN: I'm not on the PRG and I don't see those numbers, at least under the current arrangement.

MR. KUGA: I would say it's on the order of hundreds of millions of dollars over the life --

ASSOCIATE MEMBER GEESMAN: Hundreds of millions of dollars?

MR. KUGA: Yes.

PRESIDING MEMBER PFANNENSTIEL: For the utilities in total, Roy, or in PG&E?

MR. KUGA: No, I'm talking about PG&E. Over the life of the contract term.

PRESIDING MEMBER PFANNENSTIEL: Over the contract term, that you have the delta between the bid price and the MPR?

MR. KUGA: Yes.

PRESIDING MEMBER PFANNENSTIEL: Wow.

ASSOCIATE MEMBER GEESMAN: Thank you.

Do you want to add, Stuart?

MR. HEMPHILL: Well, I could add a couple more. Add hundreds of millions of dollars more from Southern California Edison, if you'd like me to.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: From your experience, as well?

MR. HEMPHILL: Yes.

ASSOCIATE MEMBER GEESMAN: I want to warn both of you guys, I'm going to figure out some way to get access to those numbers. And I'm going to test the statement that you both made. I have no reason to disbelieve it, but those are large large numbers.

MR. KUGA: Yeah, we'll be willing to work with you to provide that information to you.

ASSOCIATE MEMBER GEESMAN: Excellent.

MR. HEMPHILL: They are large numbers. I wanted to bring up the point regarding feed-in tariffs, the biggest problem I see is that feed-in tariffs don't get transmission built. And that is the single largest problem that we have in southern California in getting renewables interconnected. That's one piece.

It's also uncertain, I'm not sure how it works. Feed-in tariffs might work in a competitive retail environment. I'm not sure if

ESPs would have that same obligation, or whether that's something that was solely imposed upon the utilities. I don't know enough about what's been done elsewhere, but that's something that would be of concern.

The other point I wanted to bring up was although we called them standard offers in the 1980s, I can tell that no two contracts are the same. And in dealing with the counter-parties, they all have -- they all want to be recognized for uniqueness. And we notice this through negotiations.

Negotiations do take a long time. And it's not just our side that takes the time. What we find is developers deal with, they have equity partners, they have lenders; in some cases they have to go to courts in order to get their decisions made. And that does take time. They deal with outside attorneys; they deal with their lenders. The turnaround can be substantial and it's a big challenge.

MR. PORTER: Actually out of fairness I allowed you all to go first last time. I want to ask the nonutility parties to go first this time. So, John, you seemed ready to go.

MR. GALLOWAY: Sure, and I'm struggling with the verbosity part because this does raise a lot of issues. I mean your first question is can bilateral contracts be streamlined to achieve renewable growth in California is slightly different than should we go to a feed-in tariff.

I mean when I think about that I think about that I think of repowers as being a good example where we could, you know, where we can talk about streamlining contracts and getting real projects that could be ready to go in the near term done. We talk about repowers, we talk about it and we talk around the issue. But I think it's really time to dig into that one.

How does that translate then into, you know, the idea of doing a feed-in tariff where, you know, your streamlining is basically show up and I'll pay you this amount of money.

You know, being the good concerned scientist that I am, I would want to look at some additional analysis around the political climates in the countries where feed-in tariffs have been used, one. Where there's also a different utility structure and more of a state-owned utility structure.

I think there are a number of different factors that may have led to success in those countries that we're not really talking about here, and we don't really have time in this venue to go into. So, you know, I'm not really ready to sort of stick my thumb up and say, feed-in tariffs are good, they've worked.

They've worked in other countries like Germany and Spain to get a lot of renewables built, because there are countries like Italy, Denmark, for example, Kevin highlighted that a little bit in his presentation, you know, where Denmark ended up transitioning back into a certificate trading system because the policy didn't work for them under their conditions.

So, I guess when I first read your set of questions when they came out a couple weeks ago, you know, I sort of, you know, bounced off the walls in my office and grabbed people who really didn't care anything about feed-in tariffs, and ranted and railed that, you know, here we are talking, you know, we're facing all these challenges getting to 2010 around getting transmission built.

I think, you know, Stu's point is a very good one, that neither of those two policies is, you know, directly cuts at the heart of transmission. But the fact that we're now looking at sort of post-2010 strategies, and you know, talking about a 33 percent goal and strategies to getting there. And I think what we're doing is kind of sending the signal to the market. It's like, hey, we're thinking about doing something completely different, and you should wait until 2015 until we get the policies right, and then come back and then we can talk and we can do business.

I think it's, you know, it's an interesting academic exercise, but I'm just wondering if we're sort of sending the wrong market signal there.

It also raises additional questions around what happens to the REC from the facilities. RECs is now sort of the big issue on the table in the RPS context. Does that become meaningless if the utility no longer has a mandatory obligation.

You know, if you look at some of the European markets, you know, this is a market strategy where, you know, a generator comes in and they're paid a certain price. The utilities may not necessarily have an obligation that they have to meet. So it raises issues around the ownership of the REC.

And, you know, are we talking about doing some kind of a hybrid where the utilities continue to have an obligation like you would have under a portfolio standard layered on top of a feed-in tariff. You know, I don't know if you really want to go there right now, quite frankly.

The way it's sort of been framed in your question is you're looking at buying renewable energy offered at or below the market price referent. I think the reason why I would not want to tie that to a feed-in tariff is the market price referent is inherently gas index. I mean that is the fundamental basis of the market price referent.

And I would be bothered if you're going to peg your tariff price then to something that fluctuates with the natural gas prices, because the whole point of really increasing your renewable portfolio is to delink that from what's happening in the gas market.

So, I guess the main point that I want

to harp on, if I get to harp on anything, is just the long-term policy stability, I think. I think if you look at countries like Germany, Japan, the United States, I think where we've seen the greatest successes is not how did they tweak their policy to the nth degree in regulatory proceedings, but it's the fact that they said this is a long-term commitment and this is a long-term policy.

So, yeah, and I have to close by echoing Mr. Freedman's point about the regulatory complexity and price setting, because we get to a point where we have to set prices for a number of different technologies. Do you differentiate by different regions that may have different capacity factors for wind, for example.

You know, one of the key criticisms of this program and its policy that we have in California is its complexity. And we've spent four years trying to get the rules right. And it's just complex and we've got to simplify, simplify, simplify. This is not simplification.

So, thank you.

MR. KELLY: Yeah, I guess I'd like to respond to some of these comments, because I step back and I'm not an advocate of delay. I'm not an advocate of more complexity. And certainly we have that in California.

But I am an advocate for getting renewables online and generating renewable power. And over the last four years, I mean that'll be my test when I look at proposals, in the last four years we've had something like 240 megawatts, which is all that we've brought online.

And what have we brought online instead of that that backfills the gap that has occurred because of the nonrenewables coming online? It's more expensive resources. By definition, they're something that's priced at the MPR or higher.

So when we're in a situation where there is concern, for example, that gee, we're not getting the cheapest renewables, well, in the absence of bringing anything on we're paying for more expensive stuff.

And as we continue to litigate this stuff and nothing is coming online, it is being backfilled with stuff that is more expensive. So the cost comparisons I just don't think are particularly valid.

We need to measure whatever program

we're going to put in place and implement on its effectiveness in bringing this stuff online. Or we're going to fail. And the consumers are going to be harmed because they're not only paying more for energy, but they're facing the greenhouse gas implications of bringing on less renewables than we would otherwise wanted to.

And those are two consumer impacts that I don't think are being counted right now as we muddle our way through a very poor execution of a program, admittedly set by the Legislature. That's a problem. We've got the Legislature and they've got their ideas about how they want stuff done.

But to not consider a feed-in tariff or some other mechanism that is actually going to be effective, would be foolhardy at this point, I think.

ASSOCIATE MEMBER GEESMAN: Well, now the MPR is based on a new gas-fired combined cycle. In fact, what the real bogey is, is continuing to run the existing fleet with heat rates well in excess of 10,000 Btus an hour.

So the backfill that you speak of isn't really a new resource. It's a continued reliance on the existing resources, which this Commission has gone on record as vehemently as I think we know how to politely do, suggesting that we ought to engage in a procurement strategy designed to retire or replace those old resources.

MR. KELLY: Well, I think that's right, but we're kind of in this procurement-by-necessity now, just in time. And I know there's a couple procurements on the street. Last week there was 250 megawatts of new authorized development that's going on. But that's backfill, as well. And that will be probably new stuff. So it's both, I agree with you. But all of which are probably more expensive than the stuff that we're not bringing online today.

MR. MORRIS: Yeah, I'd actually like to amplify a little bit what Steven was saying. This is Greg Morris of the Green Power Institute.

I think we do need to judge this program on its meeting its targets in terms of renewable energy production.

Question number 9 says should the PUC require utilities to buy any renewable energy offered at or below MPR. I would say don't necessarily requirement, but certainly encourage it. Certainly encourage bilateral contracts which make sense from the utility's perspective, and obviously from the developer's perspective, to go ahead and start the process and move it through quickly.

I, too, am curious to see just how much do we really save by these competitive solicitations. And keep in mind, we've only had two MPRs set. The first one was very much a shot in the dark. The second one was based on a revised methodology.

They will become much more predictable in the future. And as they become more predictable you'll have the same effect of having developers knowing what they're bidding at in terms of the MPR. And so they may well be going to be converging more on that price anyway. But we won't know that for at least a year.

But certainly with the kind of, you know, maybe we've gotten some very cheap renewables so far, but we have nowhere near enough renewables in the aggregate to meet APTs, to meet procurement targets.

And so while we get the real cheap ones, we're not getting the full program participation that we're looking for.

ASSOCIATE MEMBER GEESMAN: Let me turn that around, Greg. Is there a project out there willing to sell to the utility at or below the MPR that hasn't been able to get a contract? Either bilateral or through the solicitations?

MR. MORRIS: I really, I can't answer that. I don't know what developers are bidding at what price, or what they're looking for. So I'm -- and also, I mean, in terms of the feed-in tariffs, which frankly I don't know very much about, but there's certainly an obvious observation to be made.

The more we're willing to pay renewables the more renewables we're going to get.

MR. KELLY: I can respond to that a little bit because I actually had a conversation with a company last week that is landfill gas kind of thing, 7-by-24 baseload, 20 megawatts. A lot of energy behind that kind of deal.

They will not deal with the California utilities in the RPS because of the complexity. And they're trying to sell to the munis. That's where they're going.

Now the munis only have so much demand;

they only represent 25 percent of the demand in the state. They're going to tap out, you know, pretty quickly.

But there is a -- I know of one company that has come to the conclusion that it is just not worth their time to do these projects in the present environment.

PRESIDING MEMBER PFANNENSTIEL: But, Steven, is that -- I mean I think that gets to the real fundamental question that's on the table here. Is what you're saying is that it's not even price, it's all about the contract negotiation, trying to find a, under the current system. That it isn't a price question. Is that what you're -- is that what this --

MR. KELLY: That's my sense. I mean, these companies --

PRESIDING MEMBER PFANNENSTIEL: And do you consider --

MR. KELLY: -- are sophisticated, --

PRESIDING MEMBER PFANNENSTIEL: -- that these are typical of renewables that are out there, but not in the process or in the queue?

MR. KELLY: Well, I'll say it's anecdotal, because I don't -- I'm not familiar with all the entities that might be looking to bid. I know I've heard from a number -- this was a small company that was able to develop two projects for 20 megawatts. I have heard from a number of my members who are not bidding, that are large, established companies building throughout the country. But they will not do it here. And as referenced earlier, FPL had made that announcement a month or so ago here.

There's a number of companies that appear to be in that boat. And, you know, it's not the PTC, I don't think. People are building with the federal law in other parts of the country. In Ohio, in Colorado, Minnesota, Texas, it is being done other places.

So the control test when you compare California with what's going on is look, are people bringing projects online in other places. Yes, they are. The PTC impacts them exactly the way it impacts us here. But it's happening in other places. And the money is diverting to those locations, the investment dollars.

So, you know, if the PTC really is a problem then we ought to figure out a bid strategy that allows people to bid with PTCs, without PTCs.

And tap into the PGC funds to backstop it, which was mentioned earlier.

Prior to SB-1078 we had money that was treated like PTCs; it was paid on a per-kilowatt hour delivered to the grid. And it was very successful. But we're not there yet.

PRESIDING MEMBER PFANNENSTIEL: Well, I'll be really interested to hear from FPL to see what their issues are.

I think the other question we heard, though, is transmission. And that's not a contract issue necessarily.

MR. KELLY: I know the project that I mentioned earlier, I don't believe is transmission constrained. It's in load centers. This is related to landfill gas and those kinds of things.

MR. PORTER: I have three speakers and five minutes. So, brevity really applies here. So, Nancy, you're the last nonutility party, so go ahead.

MS. RADER: Okay, just briefly to answer your question, Commissioner Geesman. I know that we have members who have big under the MPR and have not gotten contracts. So, the idea of offering contracts at or below, or at the MPR is attractive to me, given that the utilities are not meeting their goals.

But, again, I think we can handle that same problem by being firm on the penalties, and letting them get smart on their own about how to make it less difficult to do business with California utilities. Because it is driving people off.

MR. PORTER: Roy, I know you were interested in commenting earlier.

MR. KUGA: Yeah, I'll try to keep it brief. We don't support a feed-in tariff. We've had some experience with that. I would say that, you know, we started our process with a jointly developed contract with CEERT and with IEP and San Diego and TURN,

And we thought having a standard contract to begin with would help facilitate the process. It did. But nevertheless, in each of our negotiations there are unique circumstances that arise, whether it's phasing a contract or whether it's an emerging technology, or whether it's out-of-state, there are unique features that necessarily take some time to negotiate.

And I would say at this stage in time

I'm confident to say, you know, we're full speed ahead with our negotiating teams. So are other parties. Other parties are also negotiating multiple contracts in multiple jurisdictions. The turn time in terms of turning around contracts does take time. Lawyers are involved; I swear some of them feel like they're paid by the word that they change.

(Laughter.)

MR. KUGA: But sometimes streamlining to the point where we simplify so much, and we put in a price that sounds like it's maybe going to be more complex may ultimately take longer.

You know, Diane and I have a long history of litigating what were standard offer contracts extensively. And so we need to be mindful of what we end up with in terms of cost to customers.

In terms of, you know, being ordered to negotiate at prices below the MPR or at the MPR, that's what we're trying to do. You know, we're trying to get the best prices for customers.

In terms of, you know, the challenges that we face, again, Steve, you have my phone number. I'd be happy to contact this landfill producer. Nancy, I'd be happy to contact these wind developers.

We have an extensive outreach program. We're looking at a number of emerging technologies, as well as out-of-state. And, you know, we are engaged in bilateral negotiations as well as through our competitive solicitation.

So, you know, I'll be happy to give you my number and please send them my way. We're looking for all avenues to expand our renewable portfolio. And, you know, the feed-in tariff is just going to take more time and I think I agree with Matt, that there's loss economies of scales in certain situations. Maybe wind is not one of those. I agree that siting ease in other states may be a consideration. The fact that -- in prices for wind increases that other states may be accommodating prices higher than the MPR may be a factor.

I think we do need to understand this better. And I look forward to seeing Diane's comments.

MS. FELLMAN: Those will be --

MR. PORTER: Actually, Diane, I want to give Dan the last word on the panel.

MS. FELLMAN: I just wanted to be clear that FPL Energy's comments, not my comments.

MR. PORTER: Okay. Go ahead.

MR. FRANK: Yes. SDG&E feels pretty much the same way. We would not support feed-in tariffs. And suggesting that we take every bid that's below the MPR, SDG&E has been very aggressive and has taken the RPS program very seriously.

We've over-procured from year to year to year in our procurement plan. And we feel if we can get our existing contracts that we're negotiating, we feel like we're going to get close to the goal.

And we believe from past procurements that we've seen in RFOs, the bids that have come in, they've been very competitive. They've been below the MPR. And we think that there will be more bids that will come in that will be below the MPR and that are competitive that will allow us to hit 20 percent by 2010.

MR. PORTER: All right, thank you. Unless the Commissioners and Advisors have other questions, I wanted to throw it open to people for general public comments. So, I guess you would have to go up to the speaker podium if people have comments.

Yes, go ahead. Please identify yourself for the record.

MR. LIDDELL: Sure. My name is Don Liddell; I'm a lawyer and I represent a number of renewable developers. I don't know how to spell verbose, so this won't take very long.

I'd like to concentrate on the title of this exercise, which is minimizing contract failure and mid-course review. It seems to me that this discussion is extremely interesting, but we're in mid-course, and we should be focusing on what's in front of us now, which is thousands of megawatts in contracts that are in existence, and are in various states of performance. And focus in on those.

I'd like to concentrate back for a second on questions 6 and 7. Six is what steps are the utilities taking to minimize contract failure and delay. A very good question. They're doing a lot of things.

The second related question is what type of support would help the developers and the utilities prevent delays and contract failures.

Well, the biggest thing is transmission. Everyone says that, it's true. And fortunately, the two Commissions, the PUC and the CEC, are pursuing parallel proceedings right now. There are two at the PUC. I think most of us are aware, the RPS transmission proceeding and the RPS proceeding that focuses on contract issues.

And here, this process is moving forward and making progress. There's an interaction between them. And the decision that came out in June at the PUC I think should be looked at pretty carefully. In the RPS decision Commissioner Grueneich came out with some fairly far-reaching conclusions and recommendations to the players and the stakeholders in the business.

The context was to implement the backstop authority that exists in California's statute and has for a long time, under the Public Utilities Code, to assure utilities that if they do not get necessary rate coverage at the FERC that they'll get it from California, so that they're not disincentivized to invest in transmission.

Out of that process came a few propositions that I think are relevant here. One of them is that the PUC urged the utilities to proactively invest in that process. Specifically they were wording it, as we expect in the majority of cases, the utilities will volunteer to build and pay for, upfront, on a nondiscriminatory basis all transmission network upgrades needed to interconnect both individual renewable projects and multi-developer renewable projects.

That's the expectation. We should check and see what's actually happening. We should take that and see what can be done with it.

Similarly, the utilities were advised to capture those costs that could be recovered under the backstop authority by filing advice letters that would set up memorandum accounts, keep track of the costs, and then when the transmission project either failed or succeeded, it could then be gathered up and taken through the rate recovery process.

I don't think that there have been any. There was one before that decision that related to Tehachapi. And the suggestion was made, in Commissioner Grueneich's opinion, that that's the appropriate thing to do. As soon as a transmission project is recognized to have not certainty but probability that it will result in a CPCN or another application process, that the advice letter should be submitted and approved.

And I look around the landscape -- I represent a number of renewable developers -- and I don't see too much of that happening. It's only been a few months, so I guess my comment is that with that very clear direction, if the stakeholders, all the parties in the process, focus on that, I think that that will be a boost, a mid-course boost to that which we've got in the process now.

Similarly, --

MR. PORTER: Don, how much more do you got? Because we're right at 3:00 here.

MR. LIDDELL: Well, the last thing I wanted to talk about is streamlining, so let me be brief.

MR. PORTER: Because I'm going to spell verbose for you in just a moment.

(Laughter.)

MR. LIDDELL: That's fine. I guess I can summarize this by saying that what's needed here is this championing people are talking about. That everybody has a stake in this game. That we're all in the same boat. That the utilities should be stepping forward, being proactive and as -- that's my basic point.

I don't know that that's not happening because I'm, you know, like most people here I don't have the complete picture. But I haven't seen any real evidence that it is happening.

So my suggestion would be to take that guidance, take a look at it, and see what can come out of this process, and cross-pollinate. Thank you.

MR. PORTER: I throw it back to the Chair.

PRESIDING MEMBER PFANNENSTIEL: I think we are ready then for a break. Why don't we take until 3:15, as per the agenda. And we'll reconvene right on time and get going. Thanks.

(Brief recess.)

MR. FARROKHPAY: Thank you, Bill. Good afternoon; my name is Saeed Farrokhpay; I'm with the FERC, Office of Energy Markets and Reliability, the West Division. The west division houses the technical staff that deal with rates, markets, tariff issues for electric and gas utilities in the west.

The topic of my presentation is FERC generator interconnection and transmission expansion cost allocation policies. That's quite a broad topic. I should have probably said nuggets of that.

Before I move on I should put in the disclaimer that's in the fine print here that if by chance I express any views, those are mine and not those of the Commission or any of the Commissioners.

So what I'd like to do is give you a quick overview of order number 2003; touch on Southern California Edison's trunkline proposal that was filed about a year and a half ago at the Commission. Then give you a few examples of transmission expansion and cost allocation variations that the Commission has accepted for some of the eastern regional transmission organizations.

And then hit on a few items that might be worth considering for any alternative cost allocation proposals for FERC filing.

In order number 2003 the Commission, to remedy undue discrimination and promote new infrastructure, set a number of rules for generator interconnection procedures and agreements.

Order number 2003 and its progeny are probably several hundred pages long, but I've boiled it down to four bullet points. I hope these are the bullet points that are relevant to the discussion here.

The first two bullets deal with the assignment of costs for transmission facilities built for interconnection. The first group of costs, which are usually referred to as gen-tie facilities, generator-interconnection facilities, are those transmission facilities needed to connect the generator to where the point of interconnection is on the grid.

Consistent with the Commission's transmission pricing policies, these facilities would be directly assigned to the interconnecting customer and they would fund the cost of those facilities.

The next category is what's called the network upgrades, which are the facilities needed to accommodate the generator, the generator's output beyond the point of interconnection on the grid. And these facilities would be, under order number 2003, would be funded initially by the transmission customer -- I'm sorry, interconnection customer. And then, as the interconnection customer starts taking service over the grid, they would receive credits towards their upfront funding.

A couple of other points of interest in order number 2003, one is that the Commission emphasized that independent entities will be given more leeway in their proposals to the Commission for interconnection procedures and agreements.

The reasoning was that the independent entities don't have an interest in the market outcomes, and it's unlikely that they would propose discriminatory policies.

And the last bullet is clustering. The Commission encouraged transmission providers to use open-window period during which interconnection requests could be grouped together and studied, as a whole, to streamline the planning process.

So, with that as background, I'd like to touch on a few things, a few highlights of the proposal that Southern California Edison filed with the Commission about a year and a half ago.

I'm sure you're familiar with that proposal. But, essentially Edison proposed three transmission line segments that would integrate Tehachapi wind resources with the rest of the California ISO grid.

Edison characterized two of those facilities as grid-type facilities that provided benefits to the grid. And the third one was characterized as a trunkline, which is a radial line which under the Commission's policies would typically be directly assigned to the generators connecting to it.

Edison asked for roll-in treatment for all three line segments. We had a lot of protests from market participants, including municipalities and state water project, which basically objected to rolled-in treatment of segment three because the facilities were portrayed as not providing any benefit to the grid. Actually they were portrayed as possibly having a detrimental effect to the grid.

And they objected to having to pay for those transmission facilities when there's no benefit to them as transmission users.

The Commission granted rolled-in

treatment for segments 1 and 2 and rejected rolled-in treatment for segment 3. And I should note that in their separate statements attached to the order, then Chairman Wood and Commissioner Brownell expressed their view that had this proposal come in as a regional proposal from the California ISO that they probably would have viewed it more favorably.

So with that as background, I'd like to give you a couple of examples of where the Commission has accepted variations to its transmission pricing policies when they have been proposed by independent entities.

In southwest power pool, for example, SPP proposed and the Commission has accepted a four-month open season window for analyzing and studying transmission and interconnection service requests.

As a variation to the typical Commission approved cost allocation in that where reliability upgrade costs, the Commission has allowed SPP to assign a third of the cost to the region, and two-thirds to the local zone where the facilities are located.

And for economic upgrades and

transmission service request upgrades the cost of those would be allocated directly to those sponsors who have requested for transmission service. And they would be entitled to credits as other users take service over the facilities, and additional revenues are collected.

Another example is in PJM. PJM has, in its tariff, procedure for studying interconnection requests in six-month windows. And they have cost allocation proposals which allocate the cost to generators based on the megawatt impact that they have on the need for upgrades.

For reliability and economic upgrades they allocate costs to beneficiaries. And then in return the beneficiaries receive firm transmission rights which they can use to reduce their exposure to congestion costs.

I have another example for the midwest ISO, but really the point of these is that the Commission, when presented with proposals from independent entities, regional proposals, for cost allocation, has allowed variations from its traditional transmission cost allocation policies.

And even though these examples I gave you have to do really with the network upgrade piece of it, and not with the direct assignment costs for generator interconnections, I thought it might be helpful just to demonstrate that variations proposed by regional entities are better received.

Unfortunately, I couldn't find any example for the type of trunkline facilities that might be at issue here, the radial lines to resource-rich areas. So, it seems like, as usual, California is on the cutting edge.

So, with that here's a nonexhaustive list of things to consider as proposals are made for allocation of costs. And here I had really the radial lines gen-tie type facilities in mind.

For network upgrades I think rolling in of costs is, as you've seen in the Edison -- in the Commission's decision on Edison trunkline proposal, are a lot easier accomplished.

Certainly a proposal that comes forth from a regional entity has a much better chance of being adopted by the Commission. So last year the Commission found the California ISO to have an independent board and be an independent entity. And, as a matter of fact, allowed certain valuations in the California ISO's order 2003 compliance filing based on that finding that the California ISO is an independent entity.

Another item to consider is whether the proposal is preferential towards particular resources. I think to the extent that it doesn't favor one resource over another, or one technology over another, it certainly has a better chance of being adopted.

ASSOCIATE MEMBER GEESMAN: Why is that important to the FERC?

MR. FARROKHPAY: I think the Commission has to balance -- there has to be a reason for preference. And if it's undue, the Commission, by law, is prohibited from granting undue preference.

ASSOCIATE MEMBER GEESMAN: Between technologies?

MR. FARROKHPAY: Again, it's, the key is undue. For example, I mean I'll give you an example. For wind generators, when the Commission was dealing with the technical requirements for wind generators, the Commission allowed, based on particular need and design of systems, to have a different low voltage ride-through, which is a little different from the requirements for other generators.

But to the extent that there is no particular unique characteristic to that technology, then if it's preferential for no apparent reason, I guess that would be an issue.

ASSOCIATE MEMBER GEESMAN: Yeah, I guess I'm not concerned as much about the no apparent reason as the state may have a reason; traditionally the FERC has deferred to the states in terms of supply planning or technology choice among the states' regulatees, energy resource planning. The state may have a set of policies that compel a particular preference in which the state feels as due preference.

Is the FERC going to substitute its judgment --

MR. FARROKHPAY: This is obviously my own view. I think certainly you have commissioned, and my experience has been very conscious of state purview in resource decisions.

ASSOCIATE MEMBER GEESMAN: Let's say you had a state that wanted to further the federal policy in favor of promoting nuclear power.

MR. FARROKHPAY: Well, what I really had in mind here was that, you know, for example, when you have a proposal for transmission that reaches remote renewable rich areas, whether there is a reason not to make that same transmission available to other fuel sources.

Or to the extent that there is a proposal for let's fossil rich area; whether that should not be included.

Of course, you know, these ultimately all have to be balanced against each other. But my understanding of these is that the Commission is certainly sensitive to state policies when it makes its considerations.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. FARROKHPAY: Another item to consider possibly is the benefits a particular project provides to the grid, whether there are economies of scale. Prudent planning requires a certain sizing of transmission to reach a certain area.

To the extent that costs can be allocated to the beneficiaries, which is sometimes difficult, but, you know, if beneficiaries can be identified and the costs allocated to them, I think a proposal like that certainly would have a better chance of being adopted.

And stakeholder support, we're aware

there has been broad stakeholder support the Commission has been more receptive to the proposals.

So, like I said, this is not an exhaustive list, but just a number of things to possibly consider. That's pretty much the end of my presentation. I just wanted to put in a plug for our Folsom regional office. We have a two-person office in Folsom. If we can be of any help, if we can help answer questions or put you in touch with the right people at the Commission, feel free to call on us.

MR. KNOX: Thank you very much, Saeed, for your presentation. At this point we're going to have a very brief presentation, I think, from each of the three utilities. And perhaps you can just make those presentations from the table, and then we'll go right into the panel discussion, if that's all right. And I will bring the presentations up and go through them from up here.

I think we will start with PG&E, and Chifong Thomas from PG&E is going to talk a little bit about the transmission ranking cost report and how it's used by PG&E.

MS. THOMAS: Good afternoon; I'm Chifong

Thomas from PG&E. Well, let's see now. Okay, the transmission ranking cost report, next page please, first some advertisement here. And this is what we been doing. Since the last solicitation we been looking at the TRCR and find out that there a corridor that could be congested, based on the level we saw of generation that could materialize, in certain clusters.

And then we also overlay that on top of our assessment report. And then we identified some transmission projects which we are working on. Now, these are just, we identified them, but, of course, as we sharpen our pencils what likely happen is the scope might change.

But what we've been concentrating on is project that we can, say reconductoring, or some of the other ones within substations that does not require CPCN, and that should bring it online much faster.

So, anyway, so that's what we're doing. And besides this is the only way I can, because of FERC order 2004 this is the only way we can net our procurement side. Roy know what's going on in transmission.

So, anyway, this is one of the uses we

have for the TRCR. And allow a broadbrush look at, you know, overview of facilities to identify problems.

Next slide is pretty much what Saeed has said, is that the generator cost responsibility, if it's a generation tie, it would be the developer's cost responsibility. And we also expect that the developer would roll in the internalized wheeling charges that they would incur in bringing the power to the ISO grid.

The customers' responsibility would be, the transmission customers' responsibility would be that all network upgrades, and that would including the transmission at a cluster attributable to the bid. And that would come from the interconnection process. So hopefully our hope is that each bidder would come in, and with the interconnection study all completed in hand, and with that with the cost estimate.

But normally they don't usually do that, so we would default to the TRCR. And the TRCR is developed based on all the generation in the interconnection queue already in the basecase. So that is on top, plus the transmission addition required. So TRCR is whatever is required on top of that.

So, here's some background on it. The TRCR would provide means to insure the transmission costs are accounted for when we're considering the bids. And the methodology, estimate the actual transmission cost basically is an estimate that, you know, based on the same FERC rules that would be followed in the ISO interconnection process. So we can mirror the process and mirror the cost.

The TRCR also provide the bidder with some valuable siting information that at no cost. Because otherwise you would come in and then we have to charge them, and then do a study.

The main thing is that we can provide information so that they can, with the information, can structure their bid; can figure out site information so that they can maximize their chance of getting selected.

It is basically information sharing. We can provide it to our procurement side, as well as the developer. Like I say, this is the only way they can get information from us. Is forward looking, so it does not depend on generally coming in and putting themselves in the queue.

And then it also doesn't have to wait for the queue, of course. It's technology neutral and it provides a certain amount of speed in bid selection.

What it doesn't do is it does not prevent utility from procuring any particular resource type of resource technology, because it is technology neutral. And also doesn't advantage the nonrenewables over renewables because all it's comparing is renewables versus renewables.

It doesn't determine or affect who pays for the transmission necessary to interconnect because it is basically a selection process and a ranking process. So that to figure who would be short-listed. So it doesn't allocate cost at all.

It definitely does not replace the ISO interconnection process because before the bid the information is really sketchy. And so the amount of renewables really that we would select, that we would purchase really depends on the RPS goal. So that therefore if the Commission set the RPS goal, and we need to meet the goal, then the resource would be select -- more resource would be selected to meet the goal. It doesn't matter how high the TRCR is because that is basically a method of ranking and a method of privatization so that we know who to negotiate a contract first.

So, what it is is that before we negotiate, before we get to the second ranking of the bid, what we do is that we would have a procurement with rank all the bids, with everything except transmission. And they bring to us on the transmission side. And we would re-rank the bid with the transmission. And then the end part would be we give them a second set of ranking with the cost and with the differences so that they can go take that set. And then they can try to figure out the other stuff, such as ranking, such as the alternative commercial arrangements, you know, remarketing, swapping as available transmission. And that is not the purview of the transmission side. That is totally a procurement side function.

Now, the only thing in the second ranking the transmission side would do, is that we would also get the generation profile. And with the generation profile hopefully the developer will see, from the report they will see the way they can structure the bid. And then we would use a profile to fit into the ranking cost level, so that they would not trigger the next level of transmission cost.

And then the other one they would provide us would be a curtailment on curtailability that they would select, they would elect. So that when we look at the evaluation and we see that, you know, gee, you could have, you know, triggered the next level, what we would do is that information also get passed back on to our procurement side.

Of course, if they already elected a level of curtailment then we can take that into account when we do the ranking.

This slide, all the yellow part is all done by transmission side. And then when you go to the green part when it say other selection considerations and RPS results, -- actually it should be RFO -- that is the procurement side's responsibility.

So once we get through the yellow part, then we bring it out the door and they would take care of it.

The other thing I'd like to point out is that the basecase include all the transmission that is necessary to -- I mean, sorry -- all the generation in the interconnection queue plus the transmission necessary that's agreed upon; and also all the transmission that would be approved by the ISO and PG&E management.

And we add the TRCR on top of that. The generation associated with TRCR on top of that.

and so just before the second bidding, the second ranking evaluation, what we would do is go back and check to make sure that to see if there's anybody who had dropped out in the interconnection queue. If they would drop out, we took the transmission and would put that back into the TRCR, the ranking costs, and we basically shift it there up, the stack up.

And then the other thing we do is we also take a look at the transmission project that had been approved since the report is published. And any transmission that would be available would also be added.

So, that's basically what we're doing. And then we also -- next slide, please -- we also, the way that we had done this year is that we had 10 clusters. I mean we start out with in 2000- and, whatever the first one, we start out with seven. And then we went to 14; and this year we had 20.

And basically allows us a broad based look at the system, and to see whether transmission would be available. If not available, then since the basecase is, these levels are set up by looking at the CEC reports on resource potentials; and we also look at our bidders' response based on our RFI. And then also look at any kind of map information we can get our hands on.

And so that's how we constructed the cluster. And hopefully we can -- we will not be missing anybody.

I think that's all I have.

MR. KNOX: Okay, thank you. And next up to address TRCRs will be Linda Brown from SDG&E.

MS. BROWN: Good afternoon. While Bill's pulling up that I'll just introduce myself. I'm Linda Brown, the Manager of Transmission Planning at SDG&E.

And as I think a lot of the theme we've heard, it's a very busy area. I support everybody that says we need transmission.

The presentation that I put together today is basically geared on the six questions that were addressed in the workshop.

To the first slide. One of the questions was asked does the TRCs account for the state goals of the 20 percent, the 33 percent. The answer is no to that. There's really nothing in this TRCR process that really is looking at where the utilities are at with regards to meeting their goals.

What it does do is it does somewhat assist in evaluating RPS bids, one against another. Provides very conceptual cost estimates. We haven't had as much success as being able to let our procurement people know what the actual transmission costs are. And I'll talk about that in a little bit later.

It's based on all of the responses that we get from the RPS solicitation, so a lot of times the solicitations aren't actually what happens in reality when they go and they bid for the procurement process. We find it's very limited in its scope.

Are queued projects included? They are when we start the process. The biggest important point to realize here is that the interconnection queue is constantly changing. People are entering the queue quite a bit, and as they go on to the next phase, people get removed from the queue.

So the TRCR process is a very short timeframe from when you actually start the process. So at the beginning we look at the queue and we do model all the higher queued projects. But by the time it goes through to the PUC and actually gets published, it may be stale information.

Do we consider clustering approaches such as what was mentioned that was done in the southwest power pool, and PG&E just said, you know, they use 20 different clusters for theirs. In our first TRCR process we used seven different clusters. In the last one we used four clusters.

What we're generally finding is the renewable resource areas are very resource-specific, so it is a lot easier to do them as a cluster study rather than independently as a separate interconnection.

What are the lost opportunities? Really because there's such a short timeframe, in our opinion, to do these type of studies, we would rather you put it in conceptual estimates, that you really haven't developed an ultimate transmission plan. So without an ultimate transmission plan, you're really, you know, transmission planning is guessing at what they think the ultimate is. We're going to the engineering department, and they've done no field work, they've done no design work, so they're really guessing at what they think the engineering costs are going to be.

So, the estimates tend to be high, because the minute you put a cheaper upgrade of lesser cost out there, people get excited. And then when it turns out that it's three times as much, sometimes you get stuck with a cost cap that you might not want. So we find that as just maybe a barrier to the TRCR process.

Our recommendation really is we really believe you need to really follow the interconnection process. There was, you know, the interconnection process is a queue process that at least it gives some ranking order, and you know that the people that are in that are at least interested. They've ponied up some money; they filled out the application with the ISO.

The RPS bid evaluation, the question was asked are the costs included in the RPS solicitation or in the bid. And yes, they are.

And what kind of support can we use for the renewable resource areas. I think that we need to all think out of the box a little bit, and support new concepts with doing clustered studies, going back to the trunkline types of approaches where, because what's happening is the renewable resource areas are generally in areas where there's not a lot of load. The transmission's very old, very weak. We've got 400 megawatts out in our east county, and we've got transmission lines that are rated basically at 30 megawatts because there's not a lot of load.

Well, each one of those individual generators can't afford to pay for massive transmission. So if we look at it as a whole, look at it as a 10- or 20-year plan and develop an ultimate transmission plan, we're going to have to have some new ways to license it and ratebase it.

The ISO recently, just this June of this year proposed a new category of transmission facilities that would do exactly what I just mentioned.

And, then, of course, to us one of the most important things is to expedite the licensing process.

That's it.

MR. KNOX: Okay, thank you very much, Linda. And we'll move on to Pat Arons, Southern California Edison, at this point.

MS. ARONS: Good afternoon. I was going to say good morning, but I got up at 3:30 in the morning to catch my plane this morning, and thank you for letting me in the room with my lip gloss. I appreciate it.

I agree with the general details and content of both PG&E's and San Diego's presentations on TRCRs. And I'd like to offer some more general comments.

While I believe that perfecting TRCRs aren't going to necessarily improve the outcome of the solicitation, they do serve a very functional purpose, which is to allow a rank ordering of bids. And I have a lot of sympathy for people who have to evaluate bids in a competitive solicitation. They need a very practical tool to allow them to do some sort of rank ordering.

But I don't believe that perfecting or improving on a frequent basis really serves any outcome to improve what the result of the competitive solicitation might be.

They aren't perfect for a number of different reasons, as you heard from Linda Brown. But they don't need to be. They establish that initial rank ordering.

However, I'm somewhat troubled by the notion that the Commission spent a great deal of time, valuable time, on a process-oriented detail like a TRCR. Because we really need to be spending time talking about the real issue, which is how can this Commission get transmission built.

We need to move the focus away from processing bids and really focus on the development of transmission and how do we get that done.

Generally I think all three utilities would probably agree that we're going to be spending a lot of money to interconnect and deliver renewables no matter where those renewables are located. And building the amount of transmission needed to meet statewide goals is a huge undertaking.

So we're very concerned that we establish reasonable capital funding and spending requirements. We need to be aware that we have limited resources available for construction. We also have to be mindful of the fact that the public will have big say in siting of facilities. Licensing is going to be a big challenge because of the extent of new facilities.

So our focus needs to begin to develop plans on building transmission, thoughtful plans on how we accomplish this expansion, and not have that be the outcome of the solicitation, which is a piecemeal plan being developed here and there.

We need rational, orderly and cost effective plans that help us, allow us, as utilities, to manage the challenge of building new transmission.

I believe the CEC can be immediately useful in a couple of key areas. First, interaction with the public to gain acceptance of new facilities to interconnect renewables. Very big service that could be provided.

We could work to designate corridors where transmission can be built to access renewables pockets.

What we don't need is another collaborative type of transmission planning activity. That is a never-ending churn between competing politics of projects, ratepayer cost implications, generator cost implications, and total cost implications. And it's very difficult to work through and arrive at an ultimate plan designation.

Let's encourage renewables to get into the ISO's queue. There's nothing like reality to temper the theory of what you think you might have to build and deal with what you really do have to build.

Let's talk about how to enroll key federal agencies that control federal lands into supporting lines being built for renewables. Let's talk about bringing the PUC backstop mechanism to life. The PUC ruling could have been more helpful than it was.

And let's figure out how to simply and expedite licensing, as Linda mentioned. We also finally need to clarify the ability of the grid to integrate intermittent resources. Wind generation continues to be a great concern to Edison.

We're doing planning in Tehachapi to accommodate 4500 megawatts of intermittent wind resources that we don't have a firm handle on whether we will be able to operate such a grid.

Do we have AGC resources; what sort of minimum load conditions will occur on the grid. What's our operational issue that we face under those circumstances.

So those are some very real key issues that we need to begin to focus on if we're going to bring the renewable goal to life. And in my view perfecting TRCRs, trying to do updates doesn't get us toward some of the very big challenges that we face. And I think that by beginning to focus and talk about how to address those things, we might actually be able to get some transmission built.

Thank you.

MR. KNOX: Thank you, Pat. At this point we're going to be continuing to consider the areas of the TRCRs and interconnection of renewable generators including the issue of the Cal-ISO queue.

And at this point, Kevin Porter will be moderating the discussion. So take it away, Kevin.

MR. PORTER: Thank you, Bill. Before I open up the panel discussion I just wanted to comment on Pat's last point about integrating wind in California. Because last week in this very room we -- some of the folks in this room were here -- we offered some preliminary results of the intermittency analysis project that's being funded by the CEC PIER program. And those results will be posted on the CEC website.

But I do want to say that I was kind of disappointed truthfully as to who was not here. And I recognize it was in the middle of August, but the ISO Staff was conspicuously absent from the room. And, you know, there was a lot of folks here that were not in the room.

And I'd like to ask, as Project Manager for the IAP project, that I really would like to get some more help from some of the ISO Staff and some of the utility staff, because frankly, it's been a little thin.

So, I completely empathize with Pat's comments on incorporating 4500 megawatts of wind in Tehachapi. We have a study that we're trying to deal with it. So, once again, throw out that invitation. You know, we need the help. This is a study that is designed to address that very question. And it would be very frustrating for me, as project manager, if we end up doing what amounts to an academic study that no one really is going to believe the results in.

So, I'll step down from my podium. I just wanted to make that speech because it's something I'm spending a lot of time on. I'd hate for it to be in vain.

All right, so with that aside, --

ASSOCIATE MEMBER GEESMAN: Before you get off the pulpit, let me provide just a touch of historical context. The Commission entered into this entire study area, and have now committed several millions of dollars to several studies of the integration of intermittency.

In the fall of 2003, in response to comments by Gary Schoonyan at the adoption of our 2003 IEPR, who pleaded with us to address integration issues if we were going to make such a massive commitment to renewables.

And if we would recognize that many of the renewable projects we were likely to be relying upon the future would prove to be intermittent resources, that we were compelled to study the integration of that intermittency into the grid.

And the Commission did say that it

recognized the obligation to do so, and would make a priority of it. And I think ever since then we have tried to make a priority of it. And certainly have committed the resources to do so, and will continue to do so.

So, I really share the invitation to participate as wholeheartedly as you possibly can.

MR. PORTER: All right, notwithstanding my little commercial for a different project than we're talking about today, we do have less than an hour; and six questions, and many with subquestions. And judging from the last panel we only really covered two.

So I'm going to group the first three together, and I'm hoping everyone has these questions in front. Does anyone not have these? Just for the benefit of those who don't, the questions 10 through 12.

And Linda actually, and I think some of the other utility speakers answered some of these in their presentations, but do or should TRCRs take into account the infrastructure needed to make 20 percent by 2010, and 33 percent by 2020?

Does the TRCR reflect only online power plants, or does it include projects in the ISO queue?

And if it includes queue projects, are they reflected by a queue position or online date in allocating costs for network improvements to congested lines such as Path 15?

And how would the TRCR change if the ISO tariff was changed to reflect an aggregated approach to transmission interconnection cost allocation such as that Saeed talked about for the southwest power pool.

And if TRCRs use standard off-the-shelf cost guides, thought to be largely inaccurate, should they be used to exclude bids from further evaluation?

So I throw it open to whoever wants to take the first shot.

MS. SMUTNY-JONES: Can I just say something?

MR. PORTER: Yeah.

MS. SMUTNY-JONES: Robin Smutny-Jones with Cal-ISO. I just want to understand a statement you made earlier. I think that last week Dariush of our staff called me from a workshop here on wind. So I'm confused about our lack of participation.

MR. PORTER: He was only here for that opening session, and then he left. And so the ISO, that was the reason. I mean I, for my comment that they were largely absent from the rest of the day.

MS. SMUTNY-JONES: Okay. And I'll certainly follow up with you, because I just want to clarify for the record we make every effort to participate as fully as possible. We don't have maybe as many staff to attend every workshop, but we certainly are trying. And I'll talk with you offline about that.

MR. PORTER: Sure.

MS. SMUTNY-JONES: Thank you.

MS. THOMAS: Chifong Thomas from PG&E. For questions on whether the TRCR would be able to cover up to 20 percent by 2010 and 33 percent by 2020, what we've been doing is that we have been, in constructing the TRCR, we have been looking at the CEC report, which is that the earlier one, which is a preliminary resource, a renewable resource assessment, and then the renewable resource development report. And then also the strategic value analysis report.

And we also look at the information from bidders; and we look at the last few solicitations. And so what we're trying to do is develop a broad base look at all the levels.

And so I think that as we move on, as we move forward we should be able to come up with transmission, identify transmission project that will be enough to take care of the 20 percent in the near term. And then the 33 percent in the long term.

But actually the other thing that we have to realize, too, is that the TRCR isn't based on megawatts. And the goal is megawatt hours, is the energy. And so whether or not the transmission can actually cover all the megawatt hours really is dependent on the kind of resources procurements are actually buying. Because if you have a renewable resource that is 90 percent, for example, capacity factor, you would need a third less transmission than one that is 30 percent capacity factor.

The other part is on does the TRCR reflect only online power plants, or does it include the project in the California-ISO queue. And what we have been doing is we have been including all the projects in the ISO queue.

Now, what we are doing also too, there, of course, when you have put in all these projects in the ISO queue, with that online date plus the transmission, what would likely doing, be happening is that you would have so much resources you wouldn't have enough load.

And so what we have been doing is as we add renewables we are taking, we are shutting down fossil fuel generations that would be starting with the oldest unit first. Because I think that that would be the ideal of renewables.

And so once we start shutting them down during the, based on the oldest unit first, we're able to take a look at the transmission requirement that need to absorb the renewable generation at each cluster.

And also the clusters were done non-simultaneously. So, we basically move from one cluster; you increase generation until you hit a limit. Figure out what transmission need to go in. We increase it again and hit the limit, and so on and so forth.

How would the TRCR change the ISO tariff were -- is that the question, also? Will it change to use an aggregate approach? The TRCR is an aggregate approach. So, except that it's forward looking in that we don't wait for resources; we actually knock on the door before we start doing the studies.

But like I say, because of that the studies are conceptual and the costs are conceptual and that's exactly the reason why we are not using it for cost allocation; only for ranking.

MR. FERGUSON: Rich Ferguson, Research Director for the Center for Energy Efficiency and Renewable Technologies.

I'd just like to give a little update. On Friday the three lovely ladies here and Paul and I, at an ISO meeting down in Ontario, finally came to consensus on a 500 kV network plan for Tehachapi. So it has a ways to go yet, but we at least now have a plan we're working from after two years of effort. And thanks to George sitting back there, and a lot of other people in this room. So it takes awhile, but that's how you get transmission built, I guess.

I wanted to comment, we filed comments on the TRCR process in response to Commissioner Grueneich's ACR on Friday, so you can take a look at those and you're know what I'm going to say.

In our opinion the numbers that go into the TRCRs are so far off from what you would get if you went through the interconnection process at the ISO that they're little or no use, and maybe worse than useless. We really think they should be disregarded.

I think Pat's and Linda's sort of qualitative way of looking at it was much more useful than trying to get a number. And although, they're used just for ranking purposes, on the other hand, when we hear from the people who think they've been disadvantaged in their bidding process, by misuse of a TRCR, you have to have sympathy for those guys.

And we just don't think that the processes that are being used to make these estimates by PG&E, for example, are anything like the process that gets used by the ISO. You know, I've had this argument with Chifong for a long time about whether or not they can buy any power in Tehachapi. She says, well, no, because Path 15 is congested south and north offpeak. And the wind blows a lot offpeak.

Well, you know, that's not a condition

or a consideration that the ISO is going to use in the interconnection process. You don't even have to tell the ISO where you're going to sell your power. And it's all very nice that PG&E, you know, would like to turn off those dirty power plants on the Peninsula, and you know, import power instead, but that's not an ISO requirement, either.

One of the problems we've got, too, is that eventually this goes into some, you know, bureaucratically overseen process and the PUC has absolutely no expertise to judge whether these TRCRs are accurate or not.

We just see them as unuseful, inaccurate and impossible to fit into the bureaucratic process with any sense of oversight.

So, the questions here sort of go to, well, can we make them more accurate. And we say, no, just get rid of them.

ASSOCIATE MEMBER GEESMAN: So, what would you use prior to a system impact study to rank bids for transmission accessibility?

MR. FERGUSON: Well, that's a good question. I'm not sure that, you know, how significant it is, to tell you the truth. I haven't seen a comparison, but that would be what I would suggest to staff. Is take a look at the estimates that are made by the utilities for TRCR purposes, and take a look at what comes out of the interconnection process and see.

I mean the other question is, okay, maybe you shouldn't evaluate a bid until it goes through the interconnection process. I don't know the answer, Commissioner. You know, it's a difficult problem. But we think that the current process isn't working and you might as well junk it and wait till you get something that does work.

MS. BROWN: I'll add onto that a response to that. I think one of the things that would work well going forward in the future is to let the ISO and the PTOs transmission planning process, which is an open stakeholder process, which all the renewable merchant generators, CPUC, CEC, everybody can participate in, let them develop optimal staged plans for renewable resource areas.

You come up with an ultimate plan and maybe you don't build that plan all at once. But if the procurement department starts to get enough megawatts of the actual bids, we know it's time to go forward with that.

But if we continue to try to just guess it's a never-ending battle. So I, you know, we've done something already in the Imperial Valley study group that was an ultimate plan that was out there. There's the, you know, Sunrise, that'll be one phase of that. Tehachapi has been talked about for years, and it was not until everybody really got together and says, okay, here's an ultimate plan.

San Diego's already working right now to do that in the east county. So there's not that many renewable resource rich areas in California that we can't stage them. And let's take the time to develop the ultimate plan and figure out how it works.

MS. THOMAS: May I respond to Rich? Okay, this is Chifong Thomas from PG&E, again.

First of all, Rich, I did not say that we're not going to be able to buy any renewables because of Path 15. I say make us a deal.

(Laughter.)

MS. THOMAS: Secondly, renewables, for the TRCR we frankly have not heard any more complaint about it except from the people from

Tehachapi. And so I mean I have not heard any complaint from any other developers in other areas.

MR. FERGUSON: No, they come to me instead, right.

MS. THOMAS: That's right. And then the other part is that we would be able to, ahead of someone come in and doing a interconnection study, probably have not have any data to be able to provide for interconnection study. And so without that it would be very difficult even doing a study for someone to enter a bid.

So, if we got to wait for interconnection queue set up, we going to be waiting for a long time. And besides, we may not have enough staff to do all the work. We have a big crush of people coming in and say I want interconnection study all at once.

And so that served the purpose. And like I say, this is the only way we can let our procurement side know what's going on. And then also help us, help guide us to figure out what is the ultimate transmission plan. Because one of the major uncertainty that we are in transmission planning, we faced with is where are the resources.

And so with that, we will be able to at least see what could be happening. Because if you look at reliability study, it may find that you may need something in the same corridor, except 20 years from now. And so with something like the TRCR at least we can say, okay, we probably need something a lot sooner.

Thank you.

ASSOCIATE MEMBER GEESMAN: Chifong, the question infers, and Rich directly said, there's a fair amount of inaccuracy in the quality of information available at the TRCR point in the process.

The question suggests plus or minus 40 percent. Do you have a sense as to how accurately the TRCRs are able to predict what the ultimate interconnection and upgrade costs will be?

MS. THOMAS: Well, they're the same basis, which are conceptual costs that the planners use for, basically we use unit cost plus some sort of land assessment that we have.

ASSOCIATE MEMBER GEESMAN: Yeah, the standardized unit assumption.

MS. THOMAS: Exactly. So whatever inadequacy it would be would be washed out when you start trying to compare cluster against another cluster.

Because that's exactly the reason why we don't want to say this is a cost that, you know, use to use for allocation. Because it is for ranking purposes only.

MS. ARONS: I'd like to add onto that that you know, if you do not know what a project costs until after you've finished constructing it and all of your work orders have closed, that's the time when you really know what something costs.

At the preliminary conceptual engineering level we're using unit cost estimates; and we generally haven't even gone into the substation for a job walk. So when you get into doing preliminary engineering you're actually going into the substation; you're looking at the physical layout; you're identifying problems that you may not see on paper when you're doing conceptual type work.

So there can be a lot of variation between the level of accuracy that you get as you develop a project.

What's important about having some sort

of uniform cost basis is your, as inaccurate as your TRCRs are, perhaps you do get some sort of relative ranking consistency in terms of the inaccuracy of your costs. And I think that's adequate to get that preliminary rank ordering that you need in a bid solicitation.

MS. RADER: Nancy Rader with CalWEA again. I mentioned this in the last workshop we had, but I think one of the big problems with the TRCRs has been addressed, although people seem not to be aware of it. But one of the problems was in the interzonal transfers when you're trying to get from Tehachapi, for example, or southern California up to PG&E, the PUC's policy that says that bidders can bid to deliver in their zone and have utilities remarket that power during times of congestion gets rid of the part of the TRC associated with resolving all constraints from the buyer to the seller.

So, from our point of view, we don't, I don't think, have a big complaint from Tehachapi anymore, at least CalWEA, because that was our big complaint, which is now -- because remarketing costs associated with delivering an SP-15 should actually be a net negative adder, because of the relative cost of power during constrained times.

So, you know, I have to agree with Pat that at this point it doesn't make sense to spend a lot of time perfecting the TRCR, although we have long been an advocate of netting out the network benefits from the upgrade costs. We've made many proposals for how to do that, as have other parties. And I think, you know, it would be fine if we would do that.

But at this point I think Pat's right; we do sort of have an apples-to-apples comparison now of the different bids and their relative upgrade costs. I think it sort of affects everybody equally negatively, anybody that has a major transmission upgrade.

So, I guess we're not so worried about that and would agree with Pat and Linda and others that we really should be focusing now on developing the plans and getting the transmission built. And having that informed bidding process versus trying to push it the other way through the TRCRs, which isn't really getting us anywhere.

We made, also in our comments on Friday to the PUC, a couple of other points about things that could be done to help the process. One is that the ISO we think could better facilitate the interconnection process by batching multiple projects into one study process.

I think Stu Hemphill made the point that when one project comes out of the queue it upsets the apple cart and the study. And I think we're seeing a several-month delay because of that. And so it would be nice if we could address that issue.

A couple of other issues, but one I'll just mention is that in terms of the 39925 policy we agree with Pat's statement that the PUC could have been more helpful in its decision than it was. Could have used that policy not as a last resort, but as a first resort and being proactive in getting renewables transmission built.

But one of the things that they haven't done is look how to provide generators with certainty over what their pro rata share of the cost of a non-network line is going to be. That's just a small issue that comes up in contract negotiations where bidders need to know what their cost is going to be before they sign that PPA.

So there are a number of sort of little issues like that that have to get resolved. So, more in my written comments at the PUC, but those are the high points.

MR. PORTER: Chris, I brushed by you a couple times. Do you want to take the next --

MR. ELLISON: Chris Ellison for the American Wind Energy Association. Let me just lend my support to the sentiment that I've heard from a number of people around the table that perfecting the TRCRs is not worth the time and effort involved in doing that.

That I do think there are significant inaccuracies, and you can argue about whether they matter because we're just using this for ranking. But I think there's some other kind of big picture points that lead you to the same conclusion.

And they are, first, Steven Kelly's point in the prior panel about arguing about ranking results and picking higher cost resources than anything that we're arguing about.

Secondly, there's the point that transmission is the tail, generation is the dog. Both in terms of cost and environment impacts and everything else. So all of transmission is still a small subset of what ratepayers pay and what the impacts of our electric system are.

Third is that we're not even talking here about transmission, we're talking about bid ranking. And fourth is the point that CEERT makes in their comments filed last week, which is interesting, which is we're dealing with an even a subset of that. In other words, what we're really trying to capture here is not all transmission costs for bid ranking, but only those costs that would ultimately be borne by ratepayers as opposed to the generator.

And when you look at that, gen-tie costs are borne by the generator. The network upgrade costs are ultimately borne by the ratepayer, but they have to pass a test of net benefit to the transmission access customer before you can assign those costs.

And then if you want to look ahead to the third category potentially of renewable trunklines, although there's still a lot of uncertainty, one of the ISO proposals is to essentially reimburse the ratepayer for the cost of the transmission as generators come online.

Now there are details to be worked out. And that, by the way, is a significant difference between Edison's proposal to the FERC and what the

ISO appears to be talking about.

But when you put all that together what I think you end up with is that we have the potential for spending, and there's a long history of doing this in California, of arguing for a long time about something that isn't really all that important.

Having said that, the transmission, itself, getting the transmission built, the real on-the-ground transmission as opposed to the bid ranking, is what really matters. And an awful lot, I'm not going to go into it here, other than to say that an awful lot of the ideas that I've heard here, I think, are really where we ought to be focusing our attention. Clustering; matching up with the ISO interconnection process; and those sorts of things.

MR. PORTER: Unless Paul or Robin has anything they want to add to this, I'm going to move on to the next round of questions.

MS. SMUTNY-JONES: Can I ask a clarifying question, Kevin. I wanted to see if I understood all the utilities to be -- I think we're finding, in looking at this sort of third category, we're still trying to figure out exactly what to call it, proposal at FERC -- we are finding that looking at projects in isolation has not served us well in California. We're learning that more and more, that a more holistic planning view is better serving us.

Did I hear basically all the utilities agreeing that that's sort of the direction we need to go? Not just to look at one project at a time, but sort of on a regional basis to see what makes sense, and do more proper evaluations?

MS. THOMAS: I would agree, because if you look at one thing at a time you still have to integrate it. And what we really need is a more big picture approach, and look at something that may be happening and basically reduce risk, minimize risk of building the wrong project.

So that's the reason why we're looking at when we're overlaying the TRCR congestion corridors with the transmission assessment, the picture become clear. Because transmission assessment give you the reliability upgrade that would be needed, maybe many more years down the road. And when you overlay that on top -- the TRCR information on top of that, it give you a sense of where the corridor should be upgraded.

Not necessarily the exact project, but at least we know where to look first.

MR. FERGUSON: Can I ask a follow-up question. I mean we've thought a lot about this with Tehachapi, and I mean I think the reason Tehachapi has gotten the attention it has is because, you know, there's a widespread belief that it's an awful good resource, and so projects that are going to bid out of there are going to be relatively cheap and so on.

But if you go, you know, start looking at other clusters around the state, the problem becomes moreso, to some extent, you're sort of deciding ahead of time what renewables you're going to build by deciding what transmission you're going to build for them.

So, if you decide, okay, you know, this cluster up here and wherever is, you know, needs transmission and we think that's a good resource and so we'll build transmission up there, you're kind of, de facto, defeating the whole market process of trying to decide, you know, let the bidders decide where the least-cost projects are.

I'm not sure there's an answer, but it's a problem we've worried a lot about, you know, in the process of Tehachapi. And I'm sort of wondering that people that are fans of clustering, how do you avoid the conclusion that basically you're deciding what generation is going to get built ahead of time by deciding what transmission is going to get built.

MS. ARONS: Rich, let me try responding with a few thoughts. That we have two very extraordinary and valuable documents that date back to December of 2003 that were filed with the State Legislature.

One Chifong has already mentioned, which is the renewable potential development report. It came from the CEC. And the other was the companion report on transmission needed to interconnect those renewable areas. And in the CEC report it was looking at a goal at that time of 20 percent by 2017.

And if you take a step back from the details of what was in this report, what it does tell you is that the goals that are out there are going to require a lot of procurement and a lot of transmission construction.

So I don't think it's an either. Either this gets done or that gets done. I think that over a 10 to 20 year time period we're going to have built transmission to many different places. No one is going to get left out in the long term.

And the question for us in the short term is how do we manage the demands of construction in a manageable way. Not everyone is going to be served immediately. But over the long run I think you are going to be doing some opening up many different renewable areas.

So I would go back to take a look at that report and just see how magnificent --

MR. FERGUSON: Well, I know what you're referring --

MS. ARONS: -- the goal is.

MR. FERGUSON: -- to, but how do you decide which to do first? Do you do the biggest one? Or you do the -- you know, to me --

MS. ARONS: Well, I think, Rich, that's a great question --

MR. FERGUSON: I mean I know that --

MS. ARONS: -- and that's what we should be talking about; not focusing on perfecting a TRCR for bid evaluation purposes.

MS. BROWN: I think it kind of answers Robin's question and yours together. I mean, if you have an ultimate plan and you are somewhat together with your procurement department and the actual bids, that kind of tells you, on a regional basis, what you do first. And how much of it you do first.

MR. PORTER: Actually, Chifong, could I cut you off here, as we only have a half hour left and I still have three sets of questions to go through, so --

MS. THOMAS: Oh, dang.

MS. RADER: Kevin, can I say one little point on that? I mean -- well, Mark from FPL described the process they are going through in Texas to do that very thing, how do you pick what goes first. So we might pick up a page from there and see how they're doing it.

MR. PORTER: All right. Questions 13 through 15. Just to read them quickly. What aspects of TRCR used in previous or ongoing solicitations are most likely to result in lost opportunities, an what changes could prevent such losses?

During the RPS bid evaluation are any network upgrade costs attributed to RPS projects? And are any treated as costs paid by all transmission users?

And given that transmission development is needed to meet the state's RPS goals, how can TRCRs be revised to avoid discouraging competitively priced projects in remote but renewable-rich areas? Or how can TRCRs be revised to encourage competitively priced projects that can provide VAR support and other transmission system benefits?

MS. THOMAS: As far as solicitation, previous solicitation and that would result in lost opportunities, and the answer is no. Because like I say earlier, how much renewable we're going to purchase, procure, is really depending on the state goal. If the RPS goal is set at a certain goal, we will meet that goal.

And the TRCR is basically a ranking mechanism, so that our procurement people would know which project they should go negotiate first so that they can make the best use of the limited resources.

And however we also should note that if we do ignore transmission cost we will end up with the same amount of renewables, except it's going to be either at higher cost, or some of them may not be even deliverable.

And so I think we need to be very careful about that. I mean what's happening in Texas is the fact that, you know, they have built all these generation but no transmission.

And, of course, we don't want to go ahead and sign up a lot of renewables and it looks good on paper and it doesn't do anything for us.

The other part is that during bid evaluation are any network upgrade costs attributable to RPS projects. Well, for PG&E anyway, since we only look at the upgrade to the network, so all our transmission project that's in the TRCR, all new upgrades and will be -- it would be paid for ultimately by the ratepayers or transmission customers.

Do we need to refine the TRCR? Well, I agree with Pat. I don't think any more refinement is going to be -- I think it's a diminishing return issue here. And besides, the TRCR is technology neutral, so VAR support, we assume, at least we at PG&E assume that VAR support is already part of the equation in the bid.

And in any case, VAR -- power cannot be transported over long distances, so that even if you were to have VAR support from the renewable generation you still need some VAR support at the receiving end in order to support the voltage at the receiving end for the customers.

Benefits should certainly be counted, but should be counted separately from the cost. Because that way we would know that what is benefit and what is cost, and it would be a lot easier later on to figure out, at least figure out which bucket it is, and so that they wouldn't be double counted.

MS. ARONS: The one thing I would add to Chifong's statement, or the observation is that notoriously absent at the moment is an understanding of what facilities might be subject to the PUC backstop mechanism.

We don't have that clarity yet on what, if anything, that we might need to build that could be a generator cost responsibility during a bid evaluation ultimately becomes, you know, subject to some different backstop rate mechanism down the road, after you make a filing to the Commission, after you pass certain tests with them.

So I think getting clarity and perhaps

enrolling the Commission on the discussion of how should we consider facilities during a bid evaluation that perhaps could be subject to a backstop mechanism.

That, to me, is probably a bigger question than, you know, perfecting the number, itself. That could perhaps be the biggest benefit to some developers.

ASSOCIATE MEMBER GEESMAN: Pat, you indicated in your remarks earlier that you thought the CPUC's order on the backstop mechanism could have been improved upon. Did your company file written comments with the CPUC at the time suggesting those ways, or --

MS. ARONS: Honestly, I don't recall.

ASSOCIATE MEMBER GEESMAN: Let me ask you, what do you have in mind?

MS. ARONS: Well, I think I go back to the trunkline concept where you have the opportunity to fund it and put it in rates on the theory that it is a benefit to multiple users. It's achieving a statewide goal.

Do you -- how do you manage in a radial gen-tie type situation where you're asking a generator to pick up a pro rata share of that, managing that down the road. I think it becomes very complicated in a bid evaluation process.

ASSOCIATE MEMBER GEESMAN: I'm not as focused on the bid evaluation process as ways in which the backstop mechanism could be improved upon. Maybe I misunderstood your earlier comment, but I thought you had been mildly critical of the CPUC's order on the backstop mechanism.

MS. ARONS: Right. The concept with the trunkline is that the total cost of the trunkline is funded upfront and goes into rates on the theory that it's a benefit to multiple users; it's a regional type of facility; it's being built to, you know, accommodate a renewable procurement goal.

I think the PUC's mechanism kind of stepped away from some of those precepts and did ask generators to contribute to that. And I think it was probably an accommodation to try to get some sort of workable mechanism for backstop. But I think it perhaps made it more difficult than simplifying it.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. FERGUSON: If I could comment. We filed under the ACR comments on Friday; she had requested comments on other issues. And we also raised that issue.

As we read the initial decision basically they were saying don't worry, we're going to cover your butt. So, you know, go on, get on with the planning.

But we had the same impression that there's a huge number of issues that are raised. For example, who owns the line. If the generators are going to end up paying for it, don't they own it. Or, you know, what kind of rights do they have to the line as they, you know, make their pro rata commitment. Or how does the cash flow work.

There's just a gazillion decisions before you can turn that basic idea that you're going to guarantee cost recovery to the utility if the utility's the builder, but at the same time then you're going to have these other cash flows into the process.

And before you can actually do a deal like that you have to know who pays what, when, what their rights are, and a lot more details. So we share Pat's opinion on that.

And we made a list and our comments, which I think I sent a copy to Melissa, I think.

ASSOCIATE MEMBER GEESMAN: No, we'll pick them up in your comments --

MR. FERGUSON: Anyway, what we just did was raise a whole lot of questions like that that we encourage the Commission to try and answer as soon as possible.

MS. RADER: I would just add that if you look at the comments on the proposed decision of the utilities and CalWEA, which were very similar, there are a number of things that we asked the PUC to do to change the decision that they did not make. There was a lot farther they could have gone to use 39925 as a really proactive tool versus an absolute last resort.

For example, they make the utilities go to FERC simultaneously for a non-network line, you know, for no reason.

MR. PORTER: Any other comments on that, or these final three questions before I throw it open to the floor for comments?

MR. ELLISON: Let me just add one more thought on the lost opportunities issue. It's worth reminding ourselves that the analysis that's done for the TRCRs is essentially, first of all, peak load analysis. Secondly, it assumes all the projects, higher queue projects, go forward. And third, as noted earlier, because you end up with more generation than load, they typically have made the assumption that it's the inbasin older generation that's dispatched down.

There's a logic behind every one of those, but the combined effect of those three things is to result in greater assumptions about needed network upgrades than would be the case if you made a different set of assumptions.

And when you're dealing with wind or solar or, you know, an intermittent resource, the lost opportunity that may be there, if you use those kinds of numbers in too prescriptive a way, is to sit down in some sort of contract negotiation and say, you can either pay, you know, this cost for transmission; or we can do it the sort of conditional-firm kind of deal where you understand that you're subject to curtailment in a certain limited number of hours, or that kind of thing. Where the transmission costs go way down and you're dealing with intermittent resource anyway.

There may be opportunities to do that kind of thing that we lose in this process if we're not careful.

ASSOCIATE MEMBER GEESMAN: So you think the numbers potentially get used for something other than simply ranking bids?

MR. ELLISON: No, I do not think that they should be used for --

ASSOCIATE MEMBER GEESMAN: No. That they do --

MR. ELLISON: -- anything other than --

ASSOCIATE MEMBER GEESMAN: -- get used. That they somehow creep into negotiations of --

MR. ELLISON: I think that's possible.

ASSOCIATE MEMBER GEESMAN: Hypothetically.

MR. ELLISON: You know, I --

ASSOCIATE MEMBER GEESMAN: But would you, I mean it sounds as if we're stuck with imperfect information. It sounds as if the process currently makes use of what's considered to be the best available information.

Would you suggest that we not rank bids based on transmission cost impacts at all?

MR. ELLISON: I don't think that's as blasphemous an idea as perhaps some other people do. If you could save significant time and move things forward simply by ranking them on other criteria, I would be open to talking about that.

But having said that, I think the better answer is to try to include transmission costs in the bid process, but not spend a whole lot of time arguing about how you do it. Now, how you accomplish that is a longer conversation.

But in terms of triaging our time and effort, it's getting real transmission built and doing the ranking and getting real projects on the ground that matters. And this is a betterest enemy of the good kind of situation.

MS. THOMAS: I'd like to respond to that. First off, in our TRCR we did do both peak and offpeak. And so which is actually the reason why a large complaint was generated by the wind developers because we did do offpeak.

Secondly, when we were looking at shutting down the resources, we did do so judiciously because of the fact that where we don't shut down, all the way down to the RMR, you cut into the RMR requirements. So that we would not have any other problem, the generator not related to the renewable resources, to creep into the TRCR assessment.

So the other part that you're talking about on cutting deals, well, that's not transmission. That is procurement. And they are doing that. And as far as I know, that's how they come into the negotiation. And whether or not what they use, I'm not privy to that.

MR. ELLISON: My point was that if you rank the bids and you rank them in a way that's based upon these sorts of assumptions, you may potentially, depending on how you go forward, -- well, this sort of gets to the issue of should you throw somebody out of the bid process based on the TRCRs.

If you do that, you may be throwing somebody out of the bid process that actually has a very good project and that, with a certain amount of negotiation, could make the transmission problem go away --

MS. THOMAS: Well, in that case, then I would encourage them to come in with a real interconnection study and that would come out the real cost. And then that would go into the bid evaluation, also.

ASSOCIATE MEMBER GEESMAN: Now, this is a discussion that is hard to conduct in the abstract. It would be much better to have it informed by somebody, least of all the Commissioners, having some insight into what the actual bid looked like. And if anybody ever has been thrown out of the bid process because of a TRCR score.

MS. ARONS: The one observation I would make is in Edison's case, and our system looks quite a bit different than the PG&E system, I'm not sure how much value the TRCRs really bring to the rank ordering.

Yes, you get some kind of sign that you've got a bid that is really far away, up in northern Nevada or someplace, you know, where there's extensive transmission that has to be built. Or you get relatively minor price distinctions because of transmission if you're, you know, between two areas that both you have to build to, to access that resource, may not be of all that great value.

So, it's just something to think about.

MR. ELLISON: Again, if you've got the project with the 300-mile gen-tie, I'd just remind everybody that the generator's going to pay for that. And they're going to presumably incorporate that in their bid.

MS. THOMAS: Actually, what we had done in the past, if you remember, maybe you don't, in 2003 there were these report, companion report that Pat had talked about, the companion to a CEC report.

And in that report we identify a certain transmission that's needed. And in 2004 in the TRCR we had actually identified areas that transmission were available.

And as a result we also signing lower contracts, if people actually gravitate to those areas, we sign contracts that had made use of that information.

And so it is a tool that we would be using to evaluate, after the fact, how you would stack up, but then, you know, wouldn't it be better that you know the information rather than not knowing it? Or paying to come in with the interconnection study ahead of time.

I mean I would love to have everybody coming with interconnection study ahead of time with the exact cost.

MR. MORRIS: This is Greg Morris of the Green Power Institute. And, Commissioner, I actually did make a proposal to the effect that you theorized just now on Friday's comments, which is that maybe it would simplify and speed up the process without much loss if we didn't try and get these bid differentiations based on these very inaccurate estimates of transmission.

And I'd very much encourage the process that all three utilities have said, which is let's put our efforts into planning future transmission upgrades and additions in response to our needs, which evolve over time.

ASSOCIATE MEMBER GEESMAN: That's probably a good place to end things. I think we'll give quite a bit of focus to that in our report.

The process, as I envision it going forward, the ball now is in our court with our staff. And we will, based on -- actually we still have written comments to come in next week, but based on the workshop that we had earlier, the various materials that have been developed for these workshops, we'll put together a draft. I don't know when. We'll hold hearings, at least one, on that draft. You'll all have it in advance of the hearing.

I don't know if it will be combined with the other aspects of the 2006 IEPR update that we had originally set out to accomplish or not. As I think some of you may know, we have yet to hold our first workshop yet on load management, which was one of the topics, or on land use planning, which was the other topic we hoped to address in 2006.

But as far as this particular topic goes, I think the next step is for us to come up with a draft, and then put it out for public distribution and comment.

I want to thank everybody for your involvement today. It's really been a very very helpful process for us. And hope to see you again, soon.

We'll be adjourned.

(Whereupon, at 4:53 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission 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, 2006.