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IEPR LEAD COMMISSIONER WORKSHOP

CALIFORNIA ENERGY DEMAND UPDATED FORECAST

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Reported by:
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CALIFORNIA ENERGY COMMISSION

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COMMENTS

David Miller, PG&E

Eduardo Martinez, Edison

Will ****, San Diego

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Nate Toyama, SMUD

Doris Chow, CPUC

# I N D E X

**P R O C E E D I N G S**

DECEMBER 8, 2014 10:00 A.M.

MS. RAITT: Good morning. So welcome to today's IEPR workshop on the California energy demand updated forecast for 2015 through 2025. I'm Heather Raitt, I'm the project manager for the IEPR.

I'll begin by going over the usual housekeeping items.

Bathrooms are in the atrium. There's a snack bar on the second floor.

If there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street diagonal to the building.

Today's workshop is being broadcast through our WebEx conferencing system. Parties should be aware they're being recorded. We'll post an audio recording on the Energy Commission's website in a couple of days and a written transcript in about a month.

This morning we're going to have opening comments from Commissioners and then Chris Kavalec from the Energy Commission staff will give a presentation on the forecasts. Then we'll break for lunch and come back and hear from the utility representatives for their comments on the forecasts. Then we'll go into public comments.

We're asking parties to limit their comments to three minutes. During the public comment period, we'll take comments first from those in the room, then anybody participating by WebEx who'd like to comment, and then those who are phone-in only.

If you'd like to make comments during the public comment period, please come to the center podium and give your business card to the court reporter.

Materials for the meeting are available on the table at the entrance to the hearing room. And we welcome written comments. They're due on December 17th and the workshop notice provides the information about how to submit the written comments.

And with that, I'll give it to Commissioner Scott. Thank you.

COMMISSIONER SCOTT: Thank you, Heather, and good morning, everybody. I will not repeat all of the things that Heather said but I just want to welcome everyone to our workshop on the updated electricity forecast, and probably turn it right over to Chris unless Commissioner Douglas? All right, right to Chris.

MR. KAVALEC: Good morning. I'm Chris Kavalec from the Demand Analysis Office, and today I will be presenting our California energy demand updated forecast for 2015 to 2025, or CEDU 2014 as we call it.

But before I get started, I wanted to mention the passing of Bob Weatherwax earlier this year. He was one of our first chief forecasters way back in the late 70s and he was instrumental in developing our forecasting capability and pioneering our first end use models, and he set a standard for quality that we try to live up to since then. And he handed the mantle or the reins over to Mike Jasky and went on to a lucrative consulting career including work he did for the Energy Commission. So Bob, we'll miss you.

Okay, my presentation today, I'll be talking about how we did the forecast, the method, the critical economic and demographic assumptions that went into his forecast update; statewide and planning area baseline results.

In our forecast we distinguish now between a baseline forecast which includes efficiency from initiatives that have already been approved and funded. For example, a standard that has been implemented goes into the baseline forecast. The 2013/14 IOU efficiency programs go into the baseline forecast since they've already been approved and funded.

There are also additional efficiency potential savings that we project and we call those additional achievable energy efficiency, or AAEE. So those include efficiency from initiatives that aren't yet on the books but are reasonably likely to occur.

For example, IOU efficiency programs for 2016 and beyond, or the next update for the 2016 for Title 24 standards, those would be part of AAEE.

And combining the two forecasts, baseline with AAEE, gives us what we call a managed forecast that's used for resource planning purposes.

Okay, CEDU 2014. The main reason we're doing this is to provide an update for the California ISO's transmission planning process, or TPP, which is a proceeding that happens every year, as well as the CPUC's long term procurement planning process, or LTPP. That's on a two-year cycle; however, in the second year of that process they would like to have an update to the demand forecast.

And this forecast is meant to account for more recent projections for economic and demographic growth. At the same time, we're updating the historical data for consumption and sales from our QFER data filings from the utilities. Distributed generation. We have updated data for 2013 adoptions for (inaudible) and other technologies as well as pending adoptions in 2013 and 2014, as well as peak demand from this last summer.

We're not updating the forecast for other factors that go into the forecast. For example, efficiency distributed generation, aside from updating the historical data. Electrification, including EVs or climate change, those aren't -- those forecasts aren't being updated except to rescale as necessary.

For example, with electric vehicles, our updated consumption and peak data will have any load impacts from EVs already embedded. So therefore, we have to transform our electric vehicle forecast so that it is incremental to the last historical year.

One thing about demand response. In the version of the forecast that's posted, we didn't update the demand response numbers for demand side impacts, or the demand side version of demand response.

A couple of the utilities have requested that we update the demand response using the April 2014 filings by the IOUs. So I think between now and when the forecast is adopted, we can update the demand response. It'll have a miniscule effect on the forecast; however, demand response is receiving a lot of attention so we thought it might be prudent to update those numbers unless there is some objection from the Commissioners.

Okay. A few slides on how we did this forecast.

We wanted and needed to do this forecast fairly quickly, so rather than use our full end use models, we used our simpler econometric single equation models. We updated these models, we reestimated these models with the latest historical data. And we have models for all the major economic sectors as listed here, plus one for peak demand.

As an example, in our econometric model for residential electricity consumption, we have electricity consumption as a function of per capita income, persons per household, cooling and heating degree days, residential electricity rates, etcetera.

Another example. For peak demand we also have economic factors, plus we have annual maximum average daily temperature as a variable. The reason I mention that is because that maximum temperature along with cooling and heating degree days, they change over the forecast period because climate change impacts are incorporated, brought to us through scenarios developed by the Scripps Institute of Oceanography.

Okay. So we now have our updated econometric models and we run the models first with the economic and demographic projections that we used in our previous forecast for the 2013 IEPR, and those projections come from Moody's and Global Insight along with the Department of Finance from July of 2013.

Then we run these econometric models with newer economic and demographic data from August of this year. We have to go out an additional year. We want the forecast going out to 2025, so we had to make assumptions for rate growth and climate change impacts out one more year.

So what we did was we assumed rate growth of one percent from 2024 to 2025. Seemed pretty reasonable. And we extrapolated our climate change impacts; in other words, the impacts of climate change on our temperatures, out one year to 2025.

So we now have two sets of econometric results. We looked at the percentage differences between the two, the newer versus the older, and we apply these percentage differences to our 2013 forecast.

Net of what we call post process impacts. And what I mean by that is when we do a full forecast we run our sector models, but there are some factors that impact electricity demand that aren't captured in our models. For example, demand response, electric vehicles, efficiency from utility programs, etcetera.

Those are post process, so the sector results are adjusted for these factors.

Now, these factors aren't changing with the exception of demand response, as I mentioned earlier, so we net these out, then we apply the percentage differences from the two econometric model runs.

Before we reapply these post process impacts to the adjusted forecast, we need to develop one more year for each of these effects.

So for committed efficiency or efficiency from programs that are already in place, we used our decay function, our exponential decay function, to estimate the remaining savings out one more year from these programs.

For high speed rail, which is part of our electrification, we had numbers for 2025 from the latest high speed rail authority plan.

Demand response as it sits now, for 2025 we assumed the same as 2024.

And for electric vehicles and other electrification including the ports, we did a simple extrapolation out one year.

So now we're ready to apply our rescaled post process impacts to the adjusted forecast to give us electricity consumption forecasts for each planning area. We forecast for eight different planning areas. For example, Edison is a planning area. PG&E is a planning area. And initial peak forecasts. And I say initial because we still have to go through the process of weather normalization, which I'll talk about more in a minute.

To get to electricity sales, we need to subtract off our projected distributed generation, which as I mentioned before, is updated with 2013 adoptions and pending adoptions of DG technologies.

As I said, we need to develop weather normalized peaks for 2014 to serve as a starting point for the peak forecasts. And what I mean by weather normalized peak, it's our estimate of what peak demand would be in a given planning area, assuming "average" temperatures in that year.

The reason we do this is that our forecast, aside from climate change impacts, assumes average weather out into the future because nobody can predict the weather precisely out more than a few days.

So to be consistent with our forecast which assumes average weather, we need a starting point to assume average weather, so that's why we weather normalize our peaks for 2014.

And as usual, we provide more disaggregate results for individual load serving entities in our 1.1C demand form that's posted with our report. And sales, that should actually say net energy for load instead of sales. Net energy for load means you're adding in losses, transmission and distribution losses. So net energy for load and peak demand for what we call local areas.

For example, PG&E in the Bay Area only is a local area. Southern California Edison load in the L.A. basin is considered a local area.

So we provide these 1.5 forms and these are typically the ones that are used for the planning analyses by Cal-ISO and CPUC.

Okay. Our economic and demographic scenarios are consistent with what we used in 2013 since this is an update of the 2013 forecast, and as in 2013, we have a high demand case brought to us by Global Insight, their optimistic scenario. A mid demand case, which comes from Moody's, and it's their baseline case. And a low demand case, which is a combination of two Moody's scenarios, pessimistic and lower long-term growth.

The reason we're combining two different scenarios is that using only the pessimistic case, the economic variables reach the same level as the baseline by the end of the forecast period, so we want something that shows both lower growth in the short run and lower growth in the long run, so that's why we combine the two different scenarios.

Okay. So what does the new economic and demographic set of projections tell us?

In general, the newer projections for critical economic indicators show less growth compared to what we had in 2013, for variables like gross state product, personal income and employment.

And this is reflecting more pessimistic national forecasts by both Moody's and Global Insight. What they're telling us is that structural impacts from the recent great recession are higher than had been -- or more adverse than had been anticipated previously, so that affects long-term growth.

And by structural impacts I'm talking about things like reductions in research and development, less long-term investment, lower growth in worker productivity, less innovation, etcetera.

So all these different structural factors go to determine how much long-term investment we're going to have and how much long-term growth we're going to have. Those were affected more adversely by the great recession; therefore, less long-term growth.

This is sort of a general school of thought held by a lot of economists around the country and the fed and the congressional budget office agree with this assessment but not everyone does. UCLA, for example, is much more optimistic, at least about California's economic future. But that's a discussion we can get more into when we get into the 2015 IEPR forecast and start talking about what scenarios we want to use there.

The one exception to lower growth occurs in the manufacturing sector in the Moody's scenarios, the mid and the low. They have higher manufacturing output growth relative to the forecast in 2013, but this is coming from a change in their model methodology rather than any change in economic expectations.

So they made a change. They changed the way that they tie manufacturing output to gross domestic product, and the result was faster growth in manufacturing output.

Population projections that we used in the high and mid case are slightly lower than what we had in 2013. Both Moody's and Global Insight tie population growth to economic growth, so if you have less economic growth you're going to have a little bit less population growth. That's the way it works in their models.

In the low demand case we're using the Department of Finance population projections, and that hasn't changed since last year, they haven't put out a new official population forecast.

Okay. So let's see what some of these indicators look like at the statewide level. I'll mainly be talking about a comparison between the mid demand case from last time versus the new mid demand baseline case, because that's the case that most people care about more.

So looking first at personal income, you'll see that the drop-off. Personal income in the 2013 forecast, the red line, you'll see it's higher than all three of our new scenarios.

Comparing the mid case, by 2024 our new mid case is around 5-1/2 percent lower than our 2013 mid case.

Commercial employment did not take as much of a hit. Comparing the two mid cases, the old versus the new, the new one is a little bit less than 1 percent lower in 2024.

Manufacturing output, as I mentioned, higher. So you'll see again the red line is from the 2013 forecast.

So all three of our new scenarios basically are higher than the 2013 mid demand case throughout the forecast period.

As usual, Global Insight, the optimistic case, the high demand case, the one in green there. Global Insight assumes -- is much more optimistic about manufacturing growth than is Moody's and it's reflected in their forecast.

Statewide population, I didn't include all the cases here since they're all so close together. But the new mid demand case by 2024 is about 0.3 percent lower than it was in the last forecast.

Looking at our individual planning areas. Here's I'm showing the largest five planning areas that we forecast for. All of these planning areas took a hit. What this is showing is average annual growth for each of these economic indicators from 2013 to 2024, comparing our 2014 update versus our 2013 forecast.

And looking at personal income you'll see that each of these planning areas took a hit in terms of personal income growth. More so in southern California, particularly in the L.A. region for Edison and for LADWP.

For commercial employment you'll see that the northern California planning areas, PG&E and SMUD, actually have higher projected commercial employment growth than in 2013, whereas the southern California planning areas have lower projected growth for commercial employment versus the last forecast.

Manufacturing output higher for all five major planning areas and population growth a little bit lower.

So all these economic projections conspire to reduce our forecast a little bit compared to what we had in 2013.

So looking first at electricity consumption at the statewide level, our new mid baseline case is about 1-1/2 percent lower by 2024 than it was for our last forecast.

Electricity sales at the statewide level, our new mid baseline case is around 1.7 percent lower.

And peak demand, this is a non-coincident peak demand, meaning it's just the simple sum of planning area coincident peaks, it's down by about 1.8 percent by 2024 comparing the new mid baseline versus the old mid baseline.

Some planning area results. Here's the eight planning areas that we forecast for, and I'll show results for the five major areas.

We also have within these planning areas 16 climate zones, so climate zones being at a little bit more disaggregate level, we use those to develop our local area forecasts that I mentioned earlier in the 1.5 forms.

So first our two big publicly-owned utilities, LADWP electricity consumption. Their mid baseline case is down a little bit more than 4 percent in 2024 versus the mid baseline case from last year.

Peak demand about the same, a little bit less than 4 percent in 2024 comparing mid baseline cases.

SMUD, on the other hand, being in northern California, as I mentioned, southern California took more of a hit in terms of economic projections than northern California. Electricity consumption in the SMUD planning area is down by only 1/2 of 1 percent by 2024.

However, peak demand in 2024 is down by a whopping 7 percent, and the reason for that is we just haven't seen any load growth in SMUD in the last couple years, so we have a much lower starting point. Our actual peak in 2014 is significantly lower than we had projected in our last forecast, so a lower starting point you end up 7 percent lower by 2024.

And I checked with Nate Toyama at SMUD, and they basically have the same sort of estimate for 2014 for their starting point.

For the IOU planning areas, just some general results here. I won't be showing graphs for these, I'll be showing graphs for the managed forecasts for the IOUs since that's the more important one.

So for the three IOU planning areas, consumption and sales are down by more in southern California than in northern California, Edison and San Diego. However, Edison's peak demand doesn't drop off as much as PG&E's because of our estimate of a higher weather normalized peak in 2014 for southern California Edison. In other words, a higher peak in 2014 than we had predicted in 2013 in our last forecast in 2013.

So as I mentioned, we needed to develop a starting point for our peak projections, which we call our weather normalized peak, so we weather normalized for the three IOU what are called TAC areas, transmission access charge areas, within the California ISO.

Typically what we do is we estimate a temperature response using the last historical year through a regression analysis, and then we apply these regression coefficients to actual historical temperatures going back in years. And so we develop a series or a distribution of annual peaks using historical temperatures. The median of those, of that distribution, becomes what we call our 1 and 2, or weather normalized peak for the last historical year.

Unfortunately, the method that you use, the number of years you use to develop the distribution can have a large impact on your answer, and so we had issues. We've had issues the last couple of forecasts with the IOUs who have differing estimates for weather normalized peaks.

So what we attempted to do for this updated forecast and beyond is to develop a more robust method for doing weather normalization that we could all sort of agree on.

And the two basic differences for compared to what we typically do is, first of all, we use three years of historical data rather than one year. And the reason for that is that if you use only a single year to develop your temperature response, if that particular weather year is really screwy for whatever reason, you could end up with a screwy answer for a weather normalized peak. So therefore, three years of historical data gives us a better more complete distribution to work with, and we're not susceptible to problems caused by only using one year or one summer.

The other major difference is we're using 30 years of temperature data to develop this distribution

I talked about. Typically for PG&E and Edison we had gone back 50 or 60 years to develop the distribution. However, because of climate change and because temperatures have been warming in more recent years, we in discussions with the IOUs decided it would be more prudent to use 30 years instead of more than that to capture what's happening more recently rather than going back 50 or 60 years.

And here are the numbers we came up with as a result of this process.

From 2013 to 2014, a little bit of an increase for each of the IOU TAC areas. And so the IOUs, if they're here, may want to provide some comments about these results.

So again, these serve as the starting points for our peak demand forecasts through this weather normalization process.

Okay, on to our managed forecasts. As I mentioned before, this is where at the IOU service territorial level we apply these AAEE efficiency savings to a baseline forecast, and the combination of those two becomes what we call a managed forecast.

In the last forecast cycle the three agencies got together and agreed on two scenarios for managed forecasts, that is, two combinations of baseline and

AAEE forecasts to be used for planning purposes.

The first managed forecast, which is meant to be used for system-wide analyses, combines the mid baseline case with the mid AAEE scenario.

For more localized analyses the agencies agreed to use the mid baseline case with the low mid AAEE scenario, less AAEE savings. And the reason for that was recognition that as you go to a more disaggregated level of analysis, your uncertainty percentage-wise increases, so to be conservative, we all decided for more localized analysis mid and low mid AAEE scenarios.

Now, we don't have a new potential study from the CPUC on which to base new AAEE numbers, so AAEE has not changed since the last forecast, except as in the case of some of the post process impacts I talked about earlier, we needed to rescale.

In other words, our most recent historical loads will have whatever AAEE savings have already occurred embedded within that load data. So therefore, we need to transform the AAEE savings so that they are incremental to the last historical year.

We also needed to go out to 2025 since that's how far the forecast goes out, and we consulted with Navigant about this who did the last potential study from which these AAEE savings came from, and they did some tests in their model and they basically told us extrapolating the results that we already have gets you very close to what you would get if you ran the model for all the individual measures. So rather than go through that whole process, we just did a simple extrapolation out one more year to get AAEE savings for 2025.

So here's what we end up with in terms of AAEE savings. Apologize if the font's kind of small. But by 2025 in the mid AAEE case, we have around 22,700 gigawatt hours of additional savings.

And these numbers are meant to be subtracted directly from off the baseline forecast to give us a managed forecast.

And for peak demand by 2025 around 5700 megawatts of AAEE savings for all three IOUs combined.

And then the low mid, the other AAEE scenario we're using a little bit more than 13,000 gigawatt hours by 2025 for the three IOUs combined, and around 3500 megawatt hours of savings.

So here's what the new managed forecasts look like. You see two sets of lines here in this graph and the upcoming graphs. We have one set of lines for each managed forecast.

Managed forecast 1, or the ones that'll be higher, are the mid baseline case combined low mid AAEE savings, the scenario, the managed forecast that was used for more localized analyses.

And then the bottom two lines represent the forecasts for the managed forecasts made up of the mid baseline forecast and the mid AAEE scenario, the managed forecast to be used for system-wide analyses.

So here for PG&E, the top two lines, the red line is the managed forecast that we had in 2013, and the dark blue is our adjusted managed forecast.

So for sales for PG&E by 2024 for managed forecast 1, mid baseline and low mid AAEE, we're down around 0.3 percent. And for the other managed forecast, for system-wide analyses, we down about 0.25 percent.

For peak demand, the difference is a little bit higher, a little bit more than 1 percent difference in a our new managed forecast versus the old managed forecast.

And the reason for that is, go back to PG&E here. The new sale starts off a little bit higher in the early part of the forecast period; therefore, the difference is less by the time you get to the end of the forecast period, comparing to peak, which is about the same as what we had predicted in 2014.

For Edison, as I mentioned, the southern California planning areas took a bigger hit in terms of economic growth projections. So for sales, managed forecast 1 is down around 3 percent, and managed forecast 2, mid baseline mid AAEE, is down a little bit more than 3 percent.

Peak demand, managed forecast for Edison, not down by as much, and that's because, as I mentioned earlier when I was talking about the planning areas, looking at the beginning of the forecast period we have a higher weather normalized peak than what we had predicted in 2013, so we start off higher, so the difference between the two is lower by the end of the forecast period compared to sales.

San Diego, the two managed forecasts are down by around 1.8 percent by 2024, and peak demand managed forecasts are down by around 2.8 percent by the end of the forecast period.

Okay, so that's really all the material I had. In terms of next steps, we request any written comments from our stakeholders by Wednesday, the 17th, and we will do our best to incorporate appropriate comments into the forecast by the time it's adopted. And our plan is to adopt the forecast by the middle of January next year.

So with that, I guess I'll first ask the dais if they have any questions or comments?

COMMISSIONER SCOTT: We do not.

MR. KAVALEC: Okay. Is there any -- are there any general questions from the audience?

Okay. So we could then move to -- we could actually get done before lunch, possibly. We can then move to utility comments, assuming we have some. So first I'll start with PG&E, if you have any comments on the forecast, please. Yeah, if you could come to the microphone here and introduce yourself.

COMMISSIONER SCOTT: Chris or Heather, before we go there, can I just double check. We the on the agenda that I have the lunch break before the utility response, and I don't know if we have all of the utilities here in the room with us.

MR. KAVALEC: Good point. Okay, let's check.

COMMISSIONER SCOTT: We've got PG&E.

MR. KAVALEC: We have PG&E here.

Edison? Edison is here.

San Diego? San Diego -- pardon me? Tim Vonder, are you on the phone? Oh.

LADWP? And SMUD?

Okay. So maybe we could do the three IOUs?

COMMISSIONER SCOTT: Sounds good.

MR. KAVALEC: Okay. Yeah, and Tim Vonder is on the phone so we can hear from him, too. Okay. Go ahead, sorry.

MR. MILLAR: Good morning, everyone. So my name is Dave Millar. I am a forecaster with PG&E and I have responsibility for doing the long-term energy and peak demand forecasts.

I feel like this is like I'm talking behind me.

MR. KAVALEC: Sorry about the setup.

MR. MILLAR: That's okay. Maybe I'll just kind of stand like this.

So I want to first of all thank Chris and the Energy Commission for their hard work on the update. We've reviewed the results and we don't have any major comments about what we're seeing. It all makes sense with the transversing and the economic and demographic updates, and that this is sort of a limited update on that with no DG or major updates to the policy driver forecasts.

So we just wanted to kind of highlight a couple differences, though, with how PG&E is currently, our view on energy sales based on the bundle procurement plan that we've just filed.

So we've filed the bundle procurement plan with the mandated case, which is based on the IEPR forecasts, but this time we actually filed an alternative case which basically takes the CEC's baseline and then adds our assumptions for distributed generation and for community choice aggregation.

And so because of that, our alternative case is somewhat of a divergent view. So what we're actually seeing is our view of the company is that we're about 4 percent lower energy sales by 2024, and so that is what's currently in the forecast update, the IEPR forecast update.

So that's primarily driven by --

MR. KAVALEC: I'm sorry, that's at the service territory level?

MR. MILLAR: At the service territory level, yeah.

MALE VOICE: What percent again, I'm sorry?

MR. MILLAR: 4 percent. So that's primarily driven by distributed generation, a much higher forecast DG than what's currently assumed in IEPR.

For example, we think about there will be basically double the amount of generation from our customers by 2024 than what's currently assumed.

And then so CCA is also a major issue that we want to focus on, not necessarily for this update but for the 2015 IEPR process, and so we've taken a probabilistic approach to how we see cities and counties going to community choice aggregation, and so we actually think there's going to be about 10,000 gigawatt hours per year of our current bundle sales that's going to be served by community choice aggregators in 2024. So this is a major chunk of our bundled sales portfolio that we expect will be departing.

So at this point I think the IEPR forecast only has clean energy, and then that's held constant through the future. So it's just something that we look forward to walking collaboratively with the CEC on coming up with a probabilistic approach to how CCAs will depart our bundle portfolio.

So I think that's primarily it for us.

Again, we want to thank you for all the hard work and we understand this is sort of a limited update so at this point we're just kind of flagging these issues. And look forward to working together in the future.

MR. KAVALEC: Thanks.

COMMISSIONER SCOTT: And you're going to submit us some written comments too, right?

MR. MILLAR: Yes, absolutely.

COMMISSIONER SCOTT: Thank you.

MR. KAVALEC: And I'll just mention, as Dave said, this is a limited update and we'll definitely want to talk to you guys more about your DG forecast as well as the CCAs for the 2015 IEPR forecast.

Okay. And who do we have for Edison?

MR. MARTINEZ: Good morning, this is Eduardo Martinez. I'm a senior long-term demand forecast planner in the Long-Term Forecast Planning office at southern California Edison.

We have no formal comments. We've gone through what you posted, but we have no comments at this time.

I do have a technical question about something you mentioned on your assumptions. Is this the appropriate arena to ask you?

MR. KAVALEC: Sure.

MR. MARTINEZ: When you talked you combined two of the Moody's scenarios, the long-term and I forget which other one.

MR. KAVALEC: Short-term recession, yeah.

MR. MARTINEZ: Did you do an average, or how do I understand how you combined it?

MR. KAVALEC: Oh. So it was once scenario until 2018, the short-term recession scenario. And then from 2019 on it was the lower long-term growth scenario.

MR. MARTINEZ: Did you use some kind of manipulation, I guess, of what, a jump-off?

MR. KAVALEC: There's a little bit of a kink because when you transfer from one to the other, but it wasn't big enough to really bother us that much.

MR. MARTINEZ: Okay. Just sort of interested. Okay.

MR. KAVALEC: Okay.

MR. MARTINEZ: That's it.

MR. KAVALEC: Okay.

COMMISSIONER SCOTT: Thank you.

MR. KAVALEC: And San Diego. We can have Tim speak over the phone if he wants to.

SAN DIEGO REPRESENTATIVE: (Inaudible)

MR. KAVALEC: Oh, okay.

SAN DIEGO REPRESENTATIVE: Hello everyone. My name is Will (Inaudible). I'm with San Diego Gas and Electric. I guess I'll be speaking for Tim Vonder today.

First of all, I want to thank the Commission for having this and the staff for all their hard work as well as the Commissioners for --

COMMISSIONER SCOTT: We could wait for him if he wants to try to connect in, or...

SAN DIEGO REPRESENTATIVE: Well, he told me a couple questions that he wanted to --

COMMISSIONER SCOTT: Okay. So the two of you are good for you to go.

SAN DIEGO REPRESENTATIVE: I believe so.

COMMISSIONER SCOTT: All right. Go ahead.

SAN DIEGO REPRESENTATIVE: Tim was just wondering about the release dates for the next Global Insight and Moody's economic update as well as the release date for the Department of Finance update.

MR. KAVALEC: The Department of Finance, I don't know. I can easily check that and get back to you.

So the Moody's and Global Insight do updates monthly, and I think quarterly they have major updates. So they'll have the next major update would be the beginning of 2015 for quarter number one.

And typically what we do is we use whatever the most recent update is that we can fit in time-wise to our forecast, so it was August of 2014 for this forecast, and for the 2015 IEPR forecast it'll probably be February or March for our preliminary forecast.

SAN DIEGO REPRESENTATIVE: And I believe that's it. Okay. Thank you very much.

MR. KAVALEC: You're welcome.

COMMISSIONER SCOTT: You'll be submitting written comments as well. Okay. And Eduardo, you as well?

MR. MARTINEZ: At this point we will not but that may change.

COMMISSIONER SCOTT: Oh, okay. Okay. Thanks.

MR. KAVALEC: And I believe we had some comments from our friends at CAISO.

MR. EMMERT: Well, thanks Chris, and good morning Commissioners. My name is Bob Emmert. I'm manager for Interconnection Resources at the California ISO.

Our primary comments are really around the weather normalization process. It's a function that the ISO does as well and it's something that's actually what's part of a NERC standard to incorporate that into modeling requirements that need to be reported under various NERC standards. So we have kind of been working on our weather normalizing process as well as the ISO to improve it and to formalize it, and we've been doing that for the last few years.

We do have a concern with the weather normalized number that the CEC has come up with. It's a pretty important number since that's the base number that all the forecasts begin with, so if your numbers are a bit too high then your entire forecast is going to track higher.

And just to kind of give you some reference. For last summer 2014 our actual peak was around 44,700 megawatts in the CAISO balancing authority, and we adjusted that up in our weather normalization process to around 46,500, so nearly 2,000 megawatts higher.

But the CEC actually goes up to 49,000, so that's roughly 2,500 megawatts higher than our weather normalized number. So at this point I think we would request that we maybe even sit down with the CEC and kind of go through our numbers and do some comparison and see if we can both improve on this process and come to a number that I think would be closer and more agreeable from all the parties. Thank you.

MR. KAVALEC: Okay. I'll just respond that we do our weather normalization differently than Cal ISO does. We do weather normalized peak for each of the individual TAC areas. We add those up and then we apply a coincidence factor.

So it could be that the coincidence factor that we're applying to go from the sum of individual TACs to a weather normalized peak for CAISO is too high. We're taking a look at that now.

So certainly we should sit down in the next week or so, the sooner the better, and talk about the differences that we have.

COMMISSIONER SCOTT: Thanks, Chris. I think it would also be helpful if there are differences that are carried forward that we make sure it's clear how the Energy Commission calculation is different than the CAISO calculation so that people understand when they read the report.

MR. KAVALEC: Okay.

COMMISSIONER SCOTT: Thanks. Thanks for taking the time to sit down with CAISO.

So just for the record, we're hearing from PG&E and also from SCE that they would like to have a weather normalization conversation with Chris and the team as well. And San Diego Gas & Electric.

MR. KAVALEC: Okay. So I understand we have Nate Toyama from SMUD on the phone, so we'll ask him if he has any comments he would like to make for the record first.

MR. TOYAMA: Can you hear me, Chris, on this phone?

MR. KAVALEC: Yes. I hear you.

MR. TOYAMA: Okay, good. I have a question really. I notice that when you presented SMUD's forecast did you include any of our SMUD program energy efficiency?

MR. KAVALEC: We included only those estimates of the savings from those programs that are already in place through 2013. We didn't project efficiency program savings beyond that.

MR. TOYAMA: Okay. Then my comment would be that when we submit all our information to the various regulatory agencies including CEC of course, that we consider our managed forecast to include not only some of the items that you included, the DG, the EV, but we also have a section on energy efficiency.

And when I compared the forecast that you presented with our current forecast, we start off very similarly at the same level like you discussed, particularly with the peak demand, but going forward we have a slightly higher unmanaged peak, about 2 percent higher. It sort of levels off at 2025, but our managed peak as well as our managed sales tend to be relatively flat, roughly about maybe about a .2 to .3 percent annual growth rate versus a 1.4 percent that we have for our unmanaged (inaudible) 1.2 percent that you have for your forecast for SMUD.

So I just want to emphasize that when we do our planning for budgets, for resources, as well as submittals to the WECC for our forecast we do include that energy efficiency portion. It's roughly about 1.5 percent, and although we don't have a budget, we do have a policy for the next ten years regarding the level of energy efficiency that we hope to achieve with respect to our sales, which is roughly about 1.5 percent, and our peak, which is about .9 percent.

So those are my comments.

MR. KAVALEC: Okay. And I should mention that when I talk about these AAEE savings, right now we have estimates only for the IOUs. We want to try and develop something similar for the POUs for the 2015 IEPR forecast, so that would be taking into account what Nate's talking about, additional efficiency savings beyond what's already been budgeted. So that's something we're hoping to do for the 2015 IEPR.

MR. TOYAMA: Okay. Well, one other point is that we will be submitting our other information or rather our new information for, I guess the February and the April IEPR submittals. What I was talking about and what we've discussed earlier last week was relative to our current forecast, which was developed last year at this time, but you'll see a new one coming out pretty soon.

MR. KAVALEC: Yeah, so in your filings in

February and April you'll have a brand new forecast?

MR. TOYAMA: That's correct.

MR. KAVALEC: Okay.

MR. TOYAMA: That's it for me.

MR. KAVALEC: Okay. Thanks, Nate.

MR. TOYAMA: All right.

COMMISSIONER SCOTT: Thank you.

MR. KAVALEC: So on the line also we have some comments from Doris Chow from the CPUC.

Doris, are you there? I believe we've opened your line here.

MS. CHOW: Hi, can you guys hear me? This is Doris Chow from CPUC?

MR. KAVALEC: Yeah, we hear you.

MS. CHOW: Oh, okay. Sorry, I think (inaudible) earlier.

Yeah, I just want to say that I want to be part of the conversation when the CEC meets with the CAISO on the weather normalization part. That's all.

MR. KAVALEC: You're more than welcome, Doris.

MS. CHOW: Thanks.

COMMISSIONER SCOTT: Do we have anyone from LADWP on the line? So just for folks on the line, we're currently checking to see if anyone from LADWP is available to comment.

MR. KAVALEC: It looks like we do not.

COMMISSIONER SCOTT: All right, so why don't we do this. Why don't we do some public comment so if there are folks who are on the line now that would like to make public comment. And then I think what we would do is go ahead and break. We said that we would be back by 12:45, and so at 12:45 we'll pick up with LADWP and any remaining public comments.

But if there are folks on the line who would like to make a public comment now, why don't we go ahead and do that. Or in the room. Any hand raisers on the line there?

Okay. Well, so this is what we will do. The agenda that we have says that we would break for lunch, so we're going to go ahead and do that now, you get a little bit of extra time. And then we would be gone for one hour, so that would be 12:45.

We will reconvene at 12:45, and I hope that we will have Los Angeles Department of Water and Power on the line at that point in time so we can hear from them. And if there are any public comments at that time, we will listen to those as well. So please come back at 12:45, and thank everybody for being here.

(Off the record at 11:05 a.m.)

(Reconvene at 12:49 p.m.)

MS. RAITT: We are back from our lunch break to see if anyone else wanted to make comments on the 2014 IEPR California Energy Demand Update Forecast. So is there anyone in the room who wanted to make some public comments?

And if anyone on WebEx wants to, please use your chat function to let us know you'd like to comment.

COMMISSIONER SCOTT: Let's just note for the record that we did hear from Los Angeles Department of Water and Power, and they don't have any oral comments that they want to make today.

And so we're just looking for if there's any public comment in the room or any public comment on the phone, we'd be happy to hear that.

MS. RAITT: Thank you. No one on WebEx, and there's no callers, so...

COMMISSIONER SCOTT: Well, then thank you, everyone, for reconvening with us. I urge everyone if you've got comments that you'd like to make sure that we have, please write them down and get them to us. They are due on December 17th. And you can see by the slide here how to get the information in.

And anything else?

MS. RAITT: Thank you.

COMMISSIONER SCOTT: Okay, thank you, everyone. We're adjourned.

(Adjourned at 12:50 p.m.)

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I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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IN WITNESS WHEREOF, I have hereunto set my hand this 31st day of December 2014.

Kent J. Odell

Kent Odell
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IN WITNESS WHEREOF, I have hereunto set my hand this 31st day of December, 2014.

Terri Harper

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