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WORKSHOP

BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of,	)	
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2016 Integrated Energy Policy Report (2016 IEPR)	)	

IEPR COMMISSIONER WORKSHOP ON THE 2016

CALIFORNIA ENERGY DEMAND ELECTRICITY FORECAST UPDATE

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, DECEMBER 8, 2016

10:00 A.M.

Reported By:
Kent Odell

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Robert B. Weisenmiller, Chair

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Janea Scott

CEC Staff Present

Heather Raitt

Cary Garcia

Chris Kavalec

Stakeholders & Public Present

Dennis Peters, California Independent System Operators (CAISO)

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P R O C E E D I N G S

DECEMBER 8, 2016 10:05 A.M.

MS. RAITT: All right, we can go ahead and get started, if you'd like. Sorry.

Good morning. Welcome to this morning's workshop, Lead Commissioner Workshop on the 2016 California Energy Demand Electricity Forecast Update. I'm Heather Raitt, the IEPR Program Manager.

I'll quickly go over a few housekeeping items. Restrooms are just right outside the door. If there's an emergency, and we need to evacuate, please follow staff outside the door, and to the park, Roosevelt Park, which is caddy corner to the building.

We are recording the workshop this morning, so there will be an audio recording posted in a couple days, and a written transcript in a few weeks.

We will be having opportunity for public comment at the end of the morning's session, after we have staff presentations. Please go ahead and fill out a blue card and give it to me, or the Public Adviser, who's at the table in the back of the room.

For the WebEx participants, you can use the chat function to tell our WebEx coordinator that you'd like to make a comment during the public comment period. And at the end, we'll open lines for phone-in-only

participants.

We also welcome written comments. Written comments are due on December 19th, and the notice for this workshop explains the process for submitting comments. Thanks.

Any comments?

CHAIR WEISENMILLER: Did you go through that there will be a fire alarm?

MS. RAITT: I did. I went through all that good stuff.

CHAIR WEISENMILLER: Okay, great. Yes, yesterday, we actually had a fire alarm.

MS. RAITT: We did. We actually had a fire alarm yesterday, so it was good to remember to follow staff over to Roosevelt Park.

CHAIR WEISENMILLER: In the rain, okay.

I want to thank everyone for being here today. Obviously, one of the Energy Commission's key functions is the demand forecast, which is then used by the State in planning.

At the same time, there are lots of changes going on, now, in our loads. And while this IEPR, in some respects, is sort of a state of course, relatively simple process, we've been using it as a time to really develop the analytical tools to, next year, to really

dig into the question of what doubling energy efficiency means.

This year, we did take up the topic, two topics. One of them was weather normalization and the other was the increasing impacts of behind-the-meter solar on the forecast. There's certainly a major request from the ISO to have us sort of dig into that. And, obviously, pretty easy to see that it is having effects, now. And, over time, we expect these effects to grow bigger.

So, anyway, this was our first attempt. It's probably, again, not the last word on this topic, but at least the first word.

So, again, thanks everyone for your participation today, and looking forward to comments. And, again, it's sort of preview of next year's work, I think, as opposed to definitive. So, again, thanks.

COMMISSIONER DOUGLAS: And I think we could have brief Commissioner comments. I think we had a quick conference up here, and decided that we would just roll into the presentation. But we join in the Chair's comments, obviously, about the importance of the forecast, and the interest in the presentation, and public comment here, and how that tees us up for moving forward next year.

MS. RAITT: All right, thanks. Our first

speaker is Cary Garcia.

MR. GARCIA: Good morning. Cary Garcia, with the Demand Analysis Office. And, so, today I will be giving you an overview of the demand forecast update that we did here, for 2016.

And, so, today, I'm just going to go over the update process and what we do as far as the mechanics of the update. I'll go over a little bit of the economic and demographic assumptions that we're making for this forecast. I'll review some of the statewide baseline results. And, then, I'll go into some of the planning area results for the major planning areas.

And, then, the updated managed forecast, which include the energy efficiency estimates for the planning areas.

And, then, wrap everything up with next steps, as far as comments, and everything like that. So, and just thank you, everyone, for being here, and the Commissioners as well. Thank you for taking the time today.

So, real quickly, you know, the basis that we talked about, the basis for the update is basically to inform, you know, the ISO transmission planning processes, as well as the CPUC's procurement planning process. And, so, we do this update so we can inform

that new forecast horizon.

And, so, what we're doing, basically, is just incorporating more recent economic and demographic expectations, in comparison to what we do in the full forecast, that we did in CED-2015.

And, so, this just includes new historical data for 2015, for consumption and sales, and then new peak information for 2016.

In addition, we've -- with the help of Navigant, we extrapolated -- or, sorry, they actually reestimated 2027 for us, you know, so we can pull out the energy efficiency out to that new year, that we need for this forecast.

But, basically, for the other components, like committed efficiency, distribution generation, DR, and climate change, we're essentially just extrapolating that out or rescaling it to adjust for the new horizon.

And, so, the first step for the process is to reestimate the econometric equations that we used for the full forecast. And, so, while we estimate these for all our -- we'll run an econometric model for all the sectors, as well as peak demand. So, we have a model for residential, commercial, manufacturing, resource extraction, and construction that we refer to as industrial.

And then, ag and water pumping. The CTU, which is the transportation, communications and utilities component, and then street lighting.

So, we run all these and we do a comparison. Well, let me step back. So, we run this for the 2015, using the updated information -- sorry. We run this for 2015, what we used previously. We run another set of models for the 2016, and we apply that percentage differences to the old forecast to make that adjustment for the new information that we have.

And, so, that gives us our updated trajectories and growth rates for our forecast components.

And for those other components that I mentioned, committed efficiency, DR, and such, we basically just extrapolate those out and we treat those as a separate item. So, you have the baseline forecast, plus all these post-processed items that we attached. And that's very similar to what we do in the full forecast.

And, so, we apply the rescaled impacts to 2027, to the consumption and the initial peak forecasts that we have.

And, so, our basic sales calculation is simply removing distributed generation from our consumption forecast and calculating out what the sales would be. And this information, or this sales forecast, is updated

with the distributed generation that we have for 2015, as well as pending adoptions that we expect to occur in 2016.

And we'll talk about this a little bit later, Chris will talk about this later, but we'll also do -- we develop the weather normalized peaks as our starting point for the peak forecast.

And then, finally, after we do all these baseline forecasts, we'll have our sales forecast, our 11C forms and our 1.5 forms, broken out by LSEs. And, so, that's kind of like the last component to this whole process.

So, for the economic and demographic scenarios, we're basically using the same assumptions that we've had in 2015, just updated. Or, just the same cases, I guess, just updated for the new information.

So, our higher case is using the optimistic scenario from Global Insight. The mid case is using Moody's baseline scenario. And then, our low demand case is using Moody's lower long-term growth scenario.

And, so, here are some of the drivers that we use, some of the basic drivers that we use in the forecast. And, so, on the left there you see the CED-2015 mid that we had from the last cycle, compared to the three demand cases that we have, now, for the 2016

update.

And, so, you can see there's not too much of a difference between some of these drivers, comparing just the mid cases. So, personal income is about the same, up a little bit. The population growth is pretty flat. Manufacturing output is up in comparison to the other variables here, and I'll talk about that a little bit, in a moment. And then, commercial employment is about the same.

But you can see the spread, the difference here in that high, high optimistic scenario. But nonetheless, still has population and commercial employment kind of about the same levels. It's really that manufacturing output that tends to change a little bit and has a lot of variation, potentially. Or, a lot of -- I don't know if I'd call it uncertainty, but there's, obviously, seeing that difference between 5 percent and 2.6 percent, there's potential for a lot of growth in that sector.

And, so, basically, what's going on, according to Moody's, I saw that big difference in the manufacturing output and I was wondering, you know, what exactly was going on there. And getting feedback from Moody's, basically what we're seeing is a lot of the manufacturing growth is focused on transportation,

electronics, and then chemicals, energy and plastics. So, mostly, this is automotive technology. And they pointed to Tesla being a specific indicator of where, I guess, the growth is going to come from.

And then, we're also seeing tech and biotech growth, and innovation, developing in the Southern California and the Bay Areas. That's kind of, I guess, leading to this increased manufacturing output in comparison to the 2015 forecast.

And, so, here I have statewide personal income for the 2016 update. You can see the mid case income is about one percent higher. But it's pretty clear from the graphs here, you can see everything's pretty tightened up. So, there's really not a lot of change in comparison to what we were estimating in 2015.

If we look at another driver, statewide population, you can see there just from the history, I mean, we're not -- we're not really deviating much from what we've expected in the past and those trajectories are a little -- about the same. But you can see there's a slight dip from what population -- the expectation for population growth was. And, so, we're about one percent lower, in comparison to the 2015, looking at 2026.

But in the end, our high, mid and low cases are pretty bunched up. The high and mid case actually used

similar projections for population, whereas the low case is a little bit down, so you'll see a lot of overlap there.

As I said, statewide manufacturing is up pretty significantly. So, in the mid case, it's about 5 and a half percent higher, in comparison to the 2015 forecast. And as I said, that's mainly due to that biotech and technological innovation that we're seeing in the Bay Area and Southern California.

And then, you can see our high case is definitely, like I showed before, that 5 percent increase, you know, brings that up pretty high, out there in 2027.

Here we have statewide commercial employment. The mid case is down about, you know, half a percent in 2026, compared to the 2015 forecast. But as you can see, everything's pretty close to what we were expecting in the last cycle as far as growth rates and the future trajectory.

And, so, now, we have our statewide consumption forecast here. And, so, the actual 2015 consumption was lower than we expected. And you can see that difference there, between that last historical year and that black line, in what the projection was for 2015.

But in the end, given the new information, we're

basically seeing a similar 2026 value for the forecast. And you can see that there, the red line that represents the mid demand case, and the blue line that represents our new mid demand case are basically on top of each other, out there in 2026. And then, you see the usual spread between our high and our low demand cases.

And, so, now, we have statewide sales. Similar to consumption, a little lower in the near term. You see that adjustment there for history, in comparison to what we were projecting in the 2015 mid demand case. And, now, we have a slight dip in that near term because of the self-generation update, the updated information. But in the end, the economic growth kind of brings us back up to the end, and gets us closer to that 2026 midpoint that matches up pretty closely to what we were estimating for 2015.

And as I mentioned, we updated the AAEE savings to include 2027. But what we do, as far as the peak estimates, is simply make -- rescale it to make it incremental to 2016, because that savings has been realized and so, now, we have to start from that new starting point and then project that out.

And, so, you can see the usual spread between our different cases. We have our high baseline case. Low AAEE there, on the bottom, really which matches up

pretty closely with the mid baseline, low AAEE scenario. The mid baseline, mid AAEE, is right there in the middle. And then, we have our higher cases up there at the top, which are pretty closely aligned, as well.

But by 2027, we're looking at about 4,500 megawatts of saving for that mid AAEE case.

Similar story for the energy savings, the consumption savings. In this case, though, we're doing the energy incremental to 2015. So, the same idea, we just make that adjustment and rescale it for our starting point, and then project that out with the new savings estimates for 2027.

And the same idea here, mid baseline case is right there in the middle. And then, we have our bookend scenarios at the top and the bottom there. But, basically, these are, essentially, the same projections that we had for 2015, just rescaled and adjusted slightly for 2027.

As you may remember, in 2015, the CED 2015, we included PAU AAEE savings. And, so, now, we've included that for SMUD and LADWP. And, so, combined, in 2027, it's about 850 megawatts of savings for those planning areas, as far as peak is concerned.

For energy savings, similar to what I mentioned for the IOUs, we make that incremental to 2015 for

energy. And then, the projections go out to 2027 from there. And in 2027, we're at about 3,500 gigawatt hours of savings in the mid demand case. And you could -- yeah. Low case -- sorry, the high savings case -- sorry, high demand case has lower savings, so you see that lower green line there, in 2027.

And, so, now, this is our managed statewide sales forecast. So, it's basically taking the sales forecasts that I showed earlier, I think in slide 16, and that's just making the adjustment for the energy efficiency savings that we had estimated. And, so, we just take that baseline case and subtract off what that savings is, including the losses.

And, so, you can see we're generally seeing the same shape and the same project that we had in 2015, just adjusted slightly lower for the new sales estimates. And then, that extra AAEE brings us down a little bit. So, by 2027 -- sorry, 2026, we're about one percent lower than what we expected in 2015, on a statewide level.

Oh, I may not have mentioned this, but, so, we've updated the capacity, but the general forecast trend is the same. We use that same adoption rate that we had in the 2015. And, so, you can see that adjustment up, but the trend is just about the same for

PV adoption. So, by 2027, we're looking at about 5,000 megawatts of generation on the statewide level. And then, you have our high and our mid cases there to show the other potential projections.

In addition to the other adjustments that we made, we also included climate change impacts in the 2015 forecast. And, so, we included those in the 2016 update, as well. And here is an example of the consumption impact from climate change. And, so, this only applies to our high and mid demand case.

The low demand case, essentially -- well, let me step back one second. So, what we basically use is the temperature. That's really the main driver for the climate change impacts.

And, so, in the high and mid demand cases, we have weather scenarios that we've -- that Scripps Institute developed for us. And, so, using all those different scenarios, we come up with a climate change adjustment that, essentially, is just raising the temperature a little bit in the high and mid demand cases.

The low demand case is kind of like a business-as-usual case, so you won't see any climate change impacts. So, that's why I don't have a low case here, for you.

But the mid demand case is kind of slightly more climate change, I guess is the way to put it. And then, the high demand case would be, you know, even more drastic. And, so, you can see those effects here.

If we look at 2027, you can see that in the mid case it's about 1,000 gigawatt hours of savings -- or, sorry, not savings. Of climate change impacts. And in the high demand case, they're just under 1,200 gigawatt hours.

Similar story for the peak. But in this case, the mid demand case has about 450 megawatts of peak impact. And in the high case, we see over 600, closer to 650, I would say, in that case. And that's, basically, going to raise your peak demand, as well as your consumption up because of that increased temperatures. And we see this in the forecast, in looking at cooling degree days, and heating degree days, as well as maximum temperatures on an annual basis.

So, I'm going to move over to our planning areas that we base our forecast off of. And, so, you can see I have the PG&E, Edison, San Diego, our NCNC case, our planning area, which includes SMUD. And that's, the NCNC standards for Northern California Non-CAISO, which is basically SMUD and the Balancing Authority of Northern California.

And then, we have Planning Area 5, LADWP, Planning Area 6, Burbank, and Glendale, and Imperial, and Valley Electric, as well as the other components of the State.

And, so, today, I'm just going to go over the PG&E, Edison, San Diego, NCNC, and LADWP, since those are our largest planning areas that we work with. But this is the general basis of the forecast. So, we always start at the planning area and then we disaggregate down from here.

And as I said, these are going to be the main planning areas that I'll go over today. Just some of the basic results, and the managed sales forecasts, and managed peak forecasts.

As far as the planning area is concerned, in terms of economics and demographics, Edison and L.A. see some modest decreases in population growth, in comparison to the rest of the State.

Personal income growth is a little higher in the Central and Northern California Regions, that we've found.

And then, commercial employment has been generally reduced in all planning areas, in comparison to what we were looking at in 2015.

And then, as I mentioned, manufacturing output

is also up around the State, except in the case of the NCNC Planning Area.

Okay, so here we have the planning area sales for PG&E. And, so, keep in mind this includes more than just PG&E's service territory. This includes the whole planning area, so there will be POUs and other entities that are included in this estimate.

But, generally, the mid case here is about -- you can see it's very low, you know, fractions of a percent lower than 2015. But, we're essentially dealing with the same sales forecast that we had back in 2015.

The same kind of idea here. The main difference that we're dealing with here, though, is just the weather normalized value. That's a little bit higher than what we had in 2015. But you can see, if you look at that black line there, in the 2015 range, where 2015 estimate was a little bit lower than what actual was. So, we see that adjustment, bring everything up. And then, that green line there is what the baseline case is. And that blue line is our mid demand case, including that energy efficiency savings. So, that gap between there is essentially that savings estimate that we have.

But in the end, we're about 500 megawatts higher in the PG&E's planning area, in 2026, in comparison to

our estimate for 2015.

A similar story for Edison, Edison's planning area. The managed sales are down a little bit. The growth rates are about the same, as you can see. But in the end, we're about one percent lower than what we projected back in 2015.

The same story for the peak. And, so, once again the primary difference there is a new weather normalized starting point. And, so, that's what that gap there between the new forecast trajectory and the old one, from 2015. And then, looking at that green line, again, you can kind of see what the impact of energy efficiency savings has been.

Here we have San Diego Gas & Electric managed sales. So, starting out, we look at that green line, again, which is the baseline forecast. Our blue line showing the impact of the energy efficiency savings for San Diego's planning area. And then, our 2015 projection, which is a little higher in comparison to what we have now.

And the same story, we have a new, weather normalized starting point, and that's kind of the basis for this, that gap you see there, in addition to the increase from distributed generation impacts. So, the update to distributed generation impacts.

But in the end, we're about 2 percent lower in comparison to the 2015 forecast, if you look at 2026.

And, so, we have our managed peak here for San Diego. The mid case is, once again, about 3 percent lower than CED 2015. But the same general idea, starting at a new starting point in comparison to 2015, and make our adjustments for the energy efficiency savings.

Here, we have our Northern California Non-CAISO planning area, which includes SMUD. The mid case sales are about 4 and a half percent lower in CED 2015.

And then, we have our managed peak forecast for NCNC, and this is about 3 percent lower than what we had in the 2015 forecast. But you can see there, the trajectories are -- I wish I had, like, more exciting things here, now that I'm thinking about this. But everything -- I think the take home message today is everything is about the same as it was, just minor adjustments for kind of like the demographic information. Sorry if this is too boring for everybody.

(Laughter)

COMMISSIONER MCALLISTER: It's very comforting. But, you know, in the electric sector, we do like predictability, so it's not necessarily a bad thing.

I guess, but 4.6 percent lower, and 3 percent in

some of these numbers, I mean that is significant.

MR. GARCIA: Yeah, well --

COMMISSIONER MCALLISTER: So, I don't want to downplay it too much.

MR. GARCIA: Right, right. Keep in mind here, the NCNC, when they include the energy efficiency savings, it's done at the service territory. And, so, I'm doing this comparison because we're still working on that service area forecast, and so we can show the proper comparison. But this is just a general idea of what that drop is going to be. So, I would expect when we're just looking at SMUD, by itself, and then they're savings, you're not going to see as big of a difference between that, between those projects.

But like I said, we still have those service area forecasts that are getting done, that are broken out by LSC, and so that will give us a better idea of what this looks like. But we should have those up soon, and we'll distribute that to everybody.

But this was kind of like a quick way to look at it, on the planning area level, since that's where we start out with the forecast. But, yes, 4 percent is a big difference in this case.

Well, on that, I would say our projection was a little higher. Right? If you look at that red line

there, that was showing, basically, what we had projected in 2015. And then, when you look at the black line, the history, we were definitely a little more optimistic, I guess, as far as what the sales were going to be. So, that's like a big difference or what's mainly driving that difference.

And I guess the other, too, so if you look at NCNC and the economic and demographic information, that was one of the ones that didn't really see that bump up in manufacturing output. And, so, I think that's what's carrying over and kind of keeping that consumption a little lower than what we expected it to be.

And the same thing for the managed peak. That expectation was a little higher in 2015. So, we're dropped that down. And then, we essentially take that same projection out to 2027.

And then, here, lastly we have LADWP. This is the managed sales for them. The mid case sales is about 3 percent higher in comparison to the 2015.

You see that little, like a little, weird dip there, and that's mainly going to be cogeneration plants that we've seen are going to come online. But you can see that kind of decays off because that's not really growing. That cogen's just staying flat. And, so, once that impact happens, you see it kind of dip off and that

trajectory just takes off, again. So, it's very similar to what we had in the 2015 forecast.

And in LADWP's case, LADWP is their own planning area. Or, LADWP service area and planning area are one in the same. So, this is more of a comparable projection, compared to the other planning areas that I mentioned before.

And then, once again, the same story with peak. You see that dip there for that cogeneration, but then that kind of decays off because it remains flat. And then, you see the new forecast trajectory kind of take hold. But, really, we're only about one percent lower than what we had in the 2015 forecast.

That's about it today, for me, as far as the forecast update for the baseline forecasts. I mean, like I said, everything was kind of about the same. We see some differences for the different starting points for the peak, for the weather normalization that we'll talk about later. But by and large, the general trend has been about the same, you know, even with all the updates and the different components that we updated.

So, I'll take any questions before -- so, as Heather mentioned, we have, you know, stakeholder comments that we can include. So, if you have any comments, feel free to let us know, and we can include

those as best as we can. And then, our forecast is planned to get adopted in January. I think it's the 17th. I can't remember exactly. But that will be adopted at a business meeting in January 2017.

So, if there are any questions, or any comments from stakeholders, any comments from the dais?

CHAIR WEISENMILLER: Yeah, just one thing I would point out is you pointed out, certainly, the econ demographics is a key input. And, obviously, we always are in this wheel of wrapping up one IEPR and starting the next one, roughly, this time of the year.

So, I guess right now it's going to be in January, although the specifics, we'll have a workshop focusing on economics demographics, and try to untangle that a little bit better. Particularly, given all the potential changes on policy, on the Federal side.

MR. GARCIA: Yeah.

CHAIR WEISENMILLER: So, alerting people of upcoming attractions. But, certainly, one advantage about doing this every year is that the changes tend to be smoother, you know, as opposed to if we would, say, do it every five years, or something much longer you would see, presumably, pretty dramatic changes.

While here, we can sort of adapt or evolve to things like the economy or, you know, PV growth.

MR. GARCIA: Yeah, I think in this case -- well, from my memory, I think I came on to the Commission around that 2013 time frame, and we were coming out of that recession. And, so, I think like having this update would be -- well, in this case, obviously, I mean everything was kind of what we expected, right, business-as-usual kind of situation. The economy didn't change a whole lot.

But I think it becomes more important in those situations where you're coming out of an economic slump, or potentially we may be seeing one. Right? And, so, like you were saying, we might have different projections by January, considering the new Federal policy that we might have, and how it's going to look.

And I think the update probably is going to be more -- it will probably be a little bit more exciting, I think, around that time. It would be more -- we'll see a lot more change, potentially.

CHAIR WEISENMILLER: Yeah, I think so. Yeah, but anyway, certainly looking forward to people's comments on this and, you know, making sure we're moving forward in a process that, you know, if anyone finds any issues, we can catch them between now and the adoption. But again, encourage people to basically bring it up now, as opposed to the adoption day.

MR. GARCIA: Right. So, I guess I'll ask the audience one more time if we have anybody from any of the stakeholders, any of the utilities if you -- do we want to make comments now, Heather, or at the end. Okay, I guess we'll save those for the end, the end of the day, after our next presentation.

So, thank you very much.

MS. RAITT: Thanks, Gary. Next, is Chris Kavalec.

MR. KAVALEC: Good morning. I'm Chris Kavalec, from the Energy Assessments Division. And I'm going to discuss three topics, today.

First, a brief discussion of weather normalization and where we are, and ended up on that. My main topic's going to be the peak shift analysis that we did for the forecast update. And that segues nicely into the future work, currently in place for the 2017 IEPR, next year's forecast.

Okay, a little bit about weather normalization. When we do our peak forecast, we typically assume what we call average weather in the future. Although, we do make an adjustment for climate change. But aside from that, we're assuming average weather into the future.

So, that means that we need a starting point that also reflects average weather, and that's our

weather normalized, historical peak for the last historical year. That gives us our starting point. And it's important because peak growth is based off of that starting point.

To do that, we undertake a regression analysis to estimate the weather response of load, and we use the three most recent years to do that. And once we develop this weather response, we use 30 years' of temperature data for the different weather stations that we use to develop -- we apply these 30 years' of temperatures to our estimated weather response. And from that, we develop a distribution, and the median of that distribution serves as the one-in-two weather normalized peak for the last historical year.

We then consult with our friends at the IOUs and compare our weather normalized peaks with what they have come up with. They, typically, go through the same sort of process, although the methodology's a little bit different.

In 2016, we found that we were fairly close with all three IOUs, in terms of a weather normalized peak. So, in other words, the IOUs are relatively comfortable with our weather normalized peaks. Hopefully, I won't be contradicted here.

Anyway, we still have a remaining issue,

accounting for a lot of the difference between our estimates and the IOU estimates. And that is that we're using different data. We're using the CAISO's EMS hourly data. And the IOUs, well, in particular Edison and San Diego, are using their own load data. And there are some differences between that and the EMS hourly data.

So, we formally want to make a recommendation that a mechanism be in place so that the IOUs can use this EMS data. And not only that, that we have a discussion so that all parties understand what the data actually is, where it's measured in relation to the generation and transmission. So that the IOUs can feel comfortable using this data.

Okay, so moving on to my main topic, peak shift analysis. What is this issue? Our demand modifiers, affecting electricity consumption and peak demand, may effect hourly loads served by the load-serving entities. To the extent that this LSE-served load at the peak, which I'll call the system peak, may shift to a later hour in the day.

Particularly in the case of PV, we know that PV generation drops off quickly in the late afternoon, into the evening. And if you get enough PV generation to start with, that drop off can actually create a peak

shift. You move the system peak from late afternoon to early evening, for example.

There are other culprits, too, that have an impact, and may create or contribute to the peak shift. Additional achievable energy efficiency, electric vehicle loads and time of use rates, and their impacts.

Now, for this analysis, we're only looking at PV and AAEE. We're not, yet, at a place where we're comfortable with the 8760 profiles for electric vehicles and time of use pricing. But that is coming up and we will, hopefully, have better estimates for those two, for the 2017 IEPR.

So, I'm going to give a simple illustration, with a few graphs, showing what we mean by the peak shift. What it looks like, in a simplified example.

In this example, we're going to assume that we have consumption load, which is the sum of the system load, served by the utilities, plus PV generation. For this example, we'll assume there's no other self-gen, aside from PV.

So, we'll start with no PV generation at all, no AAEE. In that case, our hourly consumption load is the same as the system load. And the consumption peak, shown there at hour 17, or 4:00 to 5:00, is the same as the system peak. Okay.

Next, we'll add in PV generation. So, now we have two curves. The dark blue curve, for hourly consumption load, and the green curve for hourly consumption load minus PV generation. In other words, that's our new system load. And we see that our system peak has moved from 4:00 to 5:00, to 5:00 to 6:00, because of the PV generation.

Next, we'll add in AAEE savings. And that yields the red curve, which is hourly consumption load, minus PV generation, minus AAEE. In other words, our new system load.

In looking at the peak, we see that we've moved all the way to 7:00, hour 19, in terms of our system peak.

So, from that, I'll show you what we mean by a peak shift adjustment. Blowing up the graph, the previous graph on slide 9. Typically, the way that we've done forecasts, peak forecasts in the past, is we start off with the consumption peak, shown there on the dark blue curve, in hour 17. And then, from that, we estimate what PV generation is at the peak hour. And that moves us down from an hour 17, from the dark blue to the green.

And then, we estimate what additional achievable energy efficiency savings would be at peak. And that

moves us down to the red line, and hour 17, and that's what I'm calling our conventional system peak. That's typically the way that we do things.

However, we saw in our example, there, that conventional system peak, when you have peak shift, is no longer the actual system peak. The peak has now moved to hour 19. So, the difference between that conventional system peak, given by that horizontal dotted line, and the red line, at hour 19, gives you the peak shift adjustment that needs to be made in order to account for this. Okay.

So, that was our goal, here, to provide reasonable estimates of peak shift adjustments. So that users of our forecast, for resource planning, could build that into our peak forecast, or add that into our peak forecast.

I won't go through a lot of technical details of the modeling here. Just, I'll give a sort of high level overview. To do this you need, first of all, an 8760 profile for photovoltaics, which we got from using California Solar Initiative data, as analyzed by E3, in one of their analyses.

Our friend, Dr. Jaske, along with Navigant, developed an 8760 profile for additional achievable energy efficiency. And we, in house, developed a model

to protect weather normalized 8760 loads for consumption, or what I'm calling our preliminary hourly load model.

And with this hourly load model, we calibrated to our forecast update consumption peak. Meaning, basically, system peak plus PV generation, as I showed in the example. And the annual consumption load for each year.

And then, adjusting for PV and AAEE in each hour, we calculate the system peak, okay, out of the 8760.

Then, we were comparing our forecast update, one and two managed peak, our traditional peak, with these calculated system peaks for each year. The difference between those two would give you the peak shift adjustment.

One other adjustment, because we're simulating, using the simulation model for 2016, we have a peak shift estimated for that year. However, 2016 is -- our weather normalized peak for 2016 is based off actual historical loads and, therefore, would incorporate any peak shift that has already happened.

So, therefore, we measured our peak shift incremental to the peak shift estimated by the simulation model in 2016. Okay.

COMMISSIONER MCALLISTER: Chris, can I ask a quick question on this? So, you're talking about the whole system in this discussion, right, so far? I guess I'm wondering what the plan, or how much localized analysis you've done, what the plan for that is? And then, if you have any comments or kind of ideas about how the variations, you know, both at the sort of local system level, and at the net level might -- the ranges might widen and create some uncertainty about, you know, the answer that you get in any given local area?

MR. KAVALEC: Yeah, you would certainly expect to see, and I think we have seen in our limited look at the data, that the peak shift is happening to a greater degree at some of the more localized levels.

The model we're putting together here is, basically, as I called it, a preliminary model. We put this model together, basically, because we wanted to estimate a peak shift for the forecast update. We promised, in the 2015 IEPR, that that's what we would do. However, a full, comprehensive hourly load model is not going to be ready until the 2017 IEPR.

In terms of at what level we forecast the loads, that's all going to depend on the data that we end up getting. With the methodology that we put together, this methodology, as long as we have the input data and

we have the load data, we can estimate hourly loads in a much more disaggregate level. And we can also do that at a sector level, residential, commercial.

Which is important because you would expect as the distribution of the sector loads changes, for example you have less industrial load relative to residential, you'd start to see a peak year load. So, that's why it would be important to start doing these hourly load forecasts at a sector level.

Okay, in that rambling did I answer your question?

COMMISSIONER MCALLISTER: Yeah, it's good. I mean, I think we all are kind of aiming for 2017 for a lot of the implementation of the kind of new way of doing things, moving towards 2019, you know, the next time. So, big step forward. Interested in seeing that progress. So, thanks for the answer. So, you did answer my question, thanks.

MR. KAVALEC: Okay. So, for you modeling fans, here's a brief description of this hourly load model. We're basically doing a regression for each hour, for each IOU TAC area, so a total of 72 regressions. And what we're regressing is the hourly load divided by annual average hourly load, for each hour, as a function of temperatures and calendar effects, like day of the

week, weekend versus holiday, what month you're in, et cetera.

The reason that we used, as a dependent variable, the ratio, instead of the actual load is that when using ratios you can then apply, for each year, our annual forecasts from the forecast update for consumption or sales, and that gives you an 8760 for each year.

In other words, in this specification, you don't have to specifically account for econ demo, and other sources of growth, because that's already embedded in your forecast update annual numbers.

Okay. So, before we start looking at some results, let me just mention what the peak shift actually looks like for each of the IOUs.

For PG&E, we went from a conventional peak hour of 4:00 to 5:00 in the afternoon, to as late as 6:00 to 7:00 p.m. by the end of the forecast period, so a two-hour peak shift.

For Edison, we went from a conventional 3:00 to 4:00 p.m., to a 5:00 to 6:00 p.m. by the end of the forecast period.

And for San Diego, we went from a conventional 3:00 to 4:00, all the way, in some years, to 7:00 to 8:00 p.m. And San Diego's a little different in that if

you look at their load data, they have almost what you would call a double peak. In the late afternoon and then into the evening, as everyone turns their lights on. So, this spike in the early evening is almost as high as the afternoon peak, typically. So, because of that spike, that almost double peak, the peak shift actually goes to a later hour in the case of San Diego, than in the other IOUs. That, combined with the fact that in relative terms San Diego has more PV, than do the other two IOUs.

Okay. So, for PG&E, by the end of the forecast period, we're reaching a little bit less than 1,700 megawatts by 2027.

For Edison, around 1,400. Oh, I'll just mention that what we're looking at here, the dark blue shows the managed forecast for peak, that Cary showed before. And then, the green line shows the managed peak, the mid baseline, mid AAEE case when you adjust for the peak shift.

So, for Edison, we're a little bit less than 1,400 megawatts by 2027. And then, for San Diego, around 700 megawatts by the end of the forecast period for peak shift adjustment.

So, I'm referring to these peak shifts here as preliminary peak shift adjustment. And the reason for

that is we look in these graphs, like in San Diego here, you see some abrupt changes from year to year. And these changes reflect the assumptions that we make for what our average weather is going to look like in the future, for hourly temperatures.

For our model, what we did was take 15 years' of hourly temperatures, and estimate an average month, and then put together those 12 average months to give us an average year. Okay.

There are other methods of estimating a normal year for hourly temperatures, which are equally as valid. If you used a different method, then you would end up with different year-to-year changes, but you would likely have the same general upward trajectory. Okay.

So, in other words, these year-to-year jumps are an artifact of what you assume for average weather into the future. So, you can have a jump, say, when in one year your hottest temperature occurs on a Wednesday, in July, say, but the next year the hottest temperature actually falls on the weekend. And, therefore, you actually can move your -- not only the day of the peak, but you can move to a different month and have this big jump.

And the other thing is that with hourly average

peaks, we're working with hourly lumps, as opposed to instantaneous peaks. So, you're going to always have these little jumps from year to year.

So, therefore, staff -- I like to say staff, instead of I recommend, because then it sounds like there's hundreds of people supporting me. So, staff/I recommend a smoothing of this peak shift adjustment to reflect this upward trend.

And if you do that, if you change this peak shift adjustment for each IOU into a smooth upward trend, the results look like this.

For PG&E, you're getting a peak shift adjustment of 1,500 megawatts by 2027. For Edison, around 1,300. And for San Diego, 750 megawatts.

And these are not trivial changes, as you'll see. For PG&E, we're going from a flat managed forecast to an upward trending managed forecast. For Edison, a downward sloping managed forecast to an almost flat managed forecast. And then, for San Diego, we're going to downward sloping to upward sloping because of the peak shift adjustment.

Now, this leaves one more question. And that is what to do about a peak shift -- so far, we've been talking about a peak shift in what we call a one-in-two case. The question is, what do we do about a peak shift

in a one-in-ten, or more extreme weather year? Okay.

Now, in our typical annual forecast, what we do is we estimate multipliers for each IOU, derived from our 30-year distribution of temperatures, to convert our annual IEPR forecast for peak from one-in-two to one-in-ten. So, in other words, you take the one-in-two peak, the weather normalized peak, you multiply that by one plus the multiplier. That gives you the one-in-ten peak.

But a problem is when you start looking at 8760 loads, and looking at peak shift, is there's no real specific definition for what a one-in-ten year is, as opposed to an average year. So, aside from what happens on the peak day, so you have a heat storm, but you don't know -- you don't typically have a definition for the rest of the year. Is the rest of the year warmer than usual? Is it average? Or, is it cooler than usual? What you assume there is going to determine what your peak shift actually is.

So, we talked, before, about a fully, more comprehensive hourly load model. Properly quantifying a one-in-ten peak shift with the proper model would require a lot of different simulations, hundreds, maybe thousands, so that you can develop a distribution. And from that distribution, the median or one-in-two would

fall out, along with the one-in-ten, or one-in-twenty, or whatever else you want.

It would also, to do the one-in-ten properly, it would require an adjustment to AAEE, which is also estimated for a one-in-two case. And PV generation, as well. There's supposedly a little bit of a drop off in PV generation as you reach very high temperatures. I don't know how significant it is, but you would want to take that into account.

But it turns out, if you make some simplifying assumptions, for example you assume there's no change in AAEE savings or PV generation from hour to hour, and the one-in-ten, or more extreme case versus the one-in-two. You can establish a relationship between the one-in-ten peak shift and the one-in-two peak shift, which looks like this.

If you assume a peak shift from hour one to hour two, the peak shift adjustment in the one-in-ten case is going to be equal to the peak adjustment in the one-in-two case, minus the difference in consumption load between the two hours, times the one-in-ten multiplier. Okay. It just works out algebraically when you make these simplifying assumptions.

And the second term in this equation, after the minus here, the difference in consumption load times the

one-in-ten multiplier. For the magnitude of results that we're talking about here, that tends to be pretty small relative to the other term, the peak shift adjustment in the one-in-two case. Okay.

So, that means that under these simplifying assumptions, the one-in-ten peak shift will be lower than, but fairly close to the one-in-two peak shift adjustment.

So, because of that and because we don't have a fully functional hourly load model to do all these simulations, again, hundreds of us recommend that using the same peak shift adjustment in the one-in-ten case versus the one-in-two case, for this first round, at least

COMMISSIONER MCALLISTER: Yeah, actually, you've got a village behind you, right?

MR. KAVALEC: That's right.

Okay. So, that brings us to the work underway for the 2017 IEPR. We've already talked about a more comprehensive hourly load model. New AAEE estimates, coming from a new, potential studies underway for both the IOUs and POUs. And on the POU side, we're planning to expand our coverage beyond LADWP and SMUD, which was what we did in 2015.

We will also, in those potential studies, have

some scenarios related to SB 350 and AB 802. We don't have a final set of targets, obviously, yet, for SB 350. But we will at least be able to look at some different scenarios for SB 350 and build that into the 2017 IEPR forecast.

And, of course, with the importance of PV, we're continuing to tink with our PV adoption model, and we're entering into a cooperative effort with NREL, to maybe make some improvements for our PV model. So, those are the highlights.

Other things that always go on, updated econ demo, and maintenance, and updating of all our different models and so on.

So, that was it. Questions or comments?

CHAIR WEISENMILLER: Yeah, actually, I've got a few. Let's start with -- I was going to ask Dennis to explain the EMS issue, and talk about how we're going to go forward and resolve that, between the ISO and Edison. If you can step up for a second.

MR. PETERS: Good morning, Chair Weisenmiller and Commissioners. Dennis Peters, of the California ISO.

Well, first, I think, before I answer that, I just wanted to, on behalf of the ISO, express our appreciation for all of the hard work that, you k now,

Chris, and Cary, and the hundreds have done to put together this demand forecast update. And, particularly, addressing the peak shift issue. You know, we've been closely involved in all of the work, at different stages, and look forward to continuing to work with the Commission on this issue, as you develop the hourly forecast and refining, at least for this year, the one-in-ten peak shift issue.

So, with regard to the EMS data, right now that -- the data is confidential. But we are working on a mechanism, as Chris recommended, to make that data public. So, we expect that to start to happen the early part of next year.

CHAIR WEISENMILLER: And what's the difference between -- yeah, maybe this is a -- again, I'm just trying to understand. We've got two different sets of data, both of which are sort of coming from the same places. they differ. And, obviously, we've had a couple of IEPRs where we're trying to pin down the differences and at least the intent, now, is to really get it resolved next time. Right? Yes.

MR. PETERS: Yeah, the two different -- the data sets so the -- I think that Millie Miguel, Thruidian (phonetic), worked for the PUC and looked at the comparison between the Oasis data and the EMS data. And

found that, for the most part, at least for valuation of peak, it's pretty close most of the time.

But, certainly, we're going to look for a way to make that data available, at least at a TAC area level.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: Can I take advantage of him being here?

CHAIR WEISENMILLER: Sure.

COMMISSIONER MCALLISTER: So, thanks for being here, Dennis. I wanted to just about, you know, the smoothing technique that Chris proposed. I mean, it looks good and, obviously, we're more comfortable with sort of, you know, continuous curves.

But I guess I'm wondering, you know, some of the discontinuities from year to year or -- yeah, from year to year, really seem to boil down to having hourly data versus something that's more a short time frame, so you kind of get this blip. At least, that's kind of what I'm intuiting here.

So, I guess, I'm wondering how the sort of hourly forecast matches, or doesn't, you know, the more short time frames that you all use day to day, and kind of the curves that you generate, which aren't hourly. Which are, you know, much more shorter time increments than that. And if the smoothing technique kind of

captures the reality that you all see when you're actually managing the system and doing your planning?

MR. PETERS: I don't know, Jeff, you might want to address -- do you want to address that question?

MR. KAVALEC: Yeah, I'll just add to that question. Would it be helpful to us, to start thinking about shorter increments than hours?

COMMISSIONER MCALLISTER: And at least, maybe -- that's a great question. And, really, limiting it just to that kind of peak discussion. You know, not moving from 8760 analysis to something else, but just sort of trying to make sure that we're reflecting, well, that evolution in that critical peak period as it moves later. Does that help at all? Or, do we not need to do that?

MR. BILLINTON: Yeah, it's Jeff Billinton, with the ISO. I'd have to give some thought to that, as to when you're trying to look at a long-term forecast and then trying to get to the granularity. We're trying to -- we're almost mixing two things, of a longer-term forecast and the actual operating uncertainties that happen on an hour-by-hour, minute-by-minute, 15-minute time period, or 5-minute.

So, I have to think in terms of about from a long term -- the volatility is a concern, particularly

in the operating time period. And that the smoothing, the only one concern with looking at that is, as you look out in the future, what is a potential higher value that we would need to operate and plan to. The smoothing kind of takes out those high periods, which is something of concern, particularly when you get to that closer-in time period.

But with the uncertainty of the PV peak shift right now, the forecasting as we're moving towards the more hourly forecast, that should probably evolve in time. Like I say, the only concern with this smoothing is just those peak periods, the peak ones that you see in those years, which could occur, get smoothed out. And it's a question of should we be planning for that higher amount or -- because in the real time, like I say, that volatility can be difficult to manage.

CHAIR WEISENMILLER: Yeah, I would tend to say that -- my impression is the short-term forecasts are really influenced by the economy and the weather. And, so, our long-term forecast model is much smoother. And, you know, if you have an incredible heat storm, you know, you could suddenly find that fair peak. Now, having said that, you k now, obviously, no one does a particular good job of modeling longer-term weather because of the chaotic effects. And, so, trying to

figure out how to build that volatility in, you know, probably just becomes -- you know, as you get the plausible range of stuff, trying to figure out where you need to be in the average -- or estimated, and where you need to be tending a little bit more towards the high side or low side on stuff.

COMMISSIONER MCALLISTER: Yeah, I guess really the question is does the smoothing technique reflect, you know, what we want in a long-term forecast? Right? Does it lose anything? And you're saying it might lose some volatility. But we have to think about it, I guess.

CHAIR WEISENMILLER: Well, again, the issue is, in a way, longer-term are probably good. And shorter term, you know, we may have a very low sales year that has an incredible peak because of a heat storm.

COMMISSIONER MCALLISTER: Yeah.

CHAIR WEISENMILLER: So, the short-term, you know, we are trying to combine a short-term forecast and a long-term. And, typically, they're much different models.

COMMISSIONER MCALLISTER: Yeah. Yeah, for sure.

MR. KAVALEC: I'll just mention that one thing we want to avoid with our sort of preliminary, simple, hourly load model is false precision. And these hourly

jumps from year to year, while, as Jeff said, they could happen, but if you make different assumptions about what an average weather year is, they could happen in a different year.

So, in terms of encompassing the variability, that's why I kept mentioning a simulation model where you're doing hundreds or thousands of simulations because -- because of things like this, and because of one-in-two versus one-in-ten, the distribution becomes important. You want to look at the distribution and not just the median of your peak trajectory.

CHAIR WEISENMILLER: Exactly, yeah. Thanks.

A different, a couple of different questions for you. One of them is, and sort of staying at a high level. So, looking at -- you did lots of regressions. typically, how good were the fits, you know, in terms of R-squares or whatever, you know, how --

MR. KAVALEC: In the afternoon, and early evening hours, you're around 95 percent for an R-squared. But then, when you get to 2:00 in the morning, where temperature doesn't have as much of an impact, you're down around 70, 75 percent. So, that's roughly the range.

CHAIR WEISENMILLER: Okay. Yeah, I don't -- yeah, I haven't check in the report. It would be good

just to make sure we make the R-squares, or whatever, available as part of going forward.

MR. KAVALEC: Yeah, as we mentioned in our forecast report, these regression results are available on request.

CHAIR WEISENMILLER: Okay, good.

The last question is one of the things which -- I'm trying to understand where things are, now, in terms of the development of the time-of-use rates. I committed to President Picker that we were going to, as things became more settled, build that into the forecast. And, obviously, a couple of years ago, I don't think anyone had a good sense of what the time periods were, or the ratios, or anything.

But I think in terms of next year, it's really important to focus on making sure we've got the time-of-use rates in.

MR. KAVALEC: Right.

CHAIR WEISENMILLER: And I think that also gets to the question of making sure, you know, I could quote Ron Nichols on sort of what's going on behind the meter. But, obviously, lots of things are going on behind the meter. Which is why, in our data proceeding, we're really pushing to get a lot more information there. And I doubt if we're going to have much of it available next

year, but at least we're trying to move forward. So, eventually, we'll have it.

MR. KAVALEC: And kind of one of our challenges, specifically about TOU, is that our models are built off of average rates or based on average revenue for each, our end-use models. So, we're going to have to figure out a way to marry that, those forecasts, with adjustments that come from TOU that affect different hours differently. So, that's --

CHAIR WEISENMILLER: And different classes, right?

MR. KAVALEC: Classes, right.

CHAIR WEISENMILLER: Yeah, it's a significant undertaking. But, you know, I think sort of thinking back to when we originally went with the disaggregated model, as opposed to econometric, is because we needed to demonstrate the impacts of things like building and appliance standards. So, as the PUC goes through this huge shift towards time of use, obviously, they want to see how that affects need.

MR. KAVALEC: Thus, there's a reason why we have the modeling structure, the big, lumbering models that we have now. And one of the main reasons is to keep track of things like building and appliance standards.

CHAIR WEISENMILLER: Yeah. And so, certainly,

in terms of our expert panel, the more they can provide any insight for us on the time-of-use questions, that would be a good idea.

MR. KAVALEC: Yeah.

COMMISSIONER MCALLISTER: And sort of alongside that, how much of those impacts can be, you know, put into or reflected by the bottom-up model, you know, the Navigant work and the demand model, versus not. And that we have to sort of compensate for on our end.

MR. KAVALEC: Yeah, so how much can be done within the models and how much needs to be sort of post-processed.

COMMISSIONER MCALLISTER: Yeah, yeah. And like the Chair says, this is coming, this shift is definitely coming, but not in time for even the 2017 or maybe the 2018 update, either. But really worth working closely with the PUC on that, in the near term.

CHAIR WEISENMILLER: And, certainly, to the extent I encourage the utilities and the ISO to be thinking with us on how to approach those challenges.

MR. KAVALEC: Okay.

CHAIR WEISENMILLER: So, I think we're transitioning, now, to public comment. We have one person in the room. Ben Davis, please. Ben? I think we have -- well, anyway, anyone who has blue cards,

please put in your blue cards. Ben, you want to approach the microphone? Yeah, you're up, please.

MR. DAVIS: Thank you, Commissioner. It's nice to know we're on a first name basis. I am Ben Davis, Jr. You know me well enough to know my primary interest in the Energy Commission involves nuclear energy.

Today, I came in part because of your consideration of climate change in these proceedings. And my interest, in particular of that, is nuclear energy. I was dismayed to find you took out the hearing. There was no hearing in the IEPR for nuclear energy this year.

And I'll explain why it relates to this particular climate change impact peak, which was part of the first speaker's presentation.

I'm, basically, trying to find out, if I understand the draft IEPR, you basically took out nuclear energy because there's an agreement which could close the plant in 2024-25. Of course, it could close this year because the NRC is having proceedings about seismic activity. And it could close in 2018 because there's litigation going on the Land Commissions hearing, that would deny -- could potentially deny Diablo Canyon lease.

So, I'm trying to determine whether or not

closing Diablo Canyon sooner, rather than later, would have any impact on our global warming emissions. Climate change, in particular.

And reading everything I can, in all the hearings before the Energy Commission, I can find nothing that suggests we could not compensate, as a State, and close that plant, now, if we found that the risks did not outweigh the benefits.

Am I getting those two in order? the benefits did not outweigh the risks. If we found that to be true, which would be analyzed further by the NRC this year, would it create any more greenhouse gases? And from everything I've read, the Energy Commission has no official position on this, and should not. It's too -- correct me if I'm wrong in that assumption, by the way. But it's too delicate a question. That in your Integrated Energy Policy Report, your draft, you state that nuclear provides 9 percent of the energy to California.

But looking into that further, you did not make it clear that that included Palos Verdes, without which it brings it down to six. And it almost did not consider the fact that we're in the worst drought year that we've been in, in the last 20 or 30 years. And if it was an average water year, or as I did, I averaged

the last 20 years and found out it brings it down closer to five percent of the energy actually consumed in California, by Energy Commission proceedings. And that doesn't include generation less than one megawatt, which is all of our new, rooftop solar. Which brings it down, potentially, closer to four.

When you consider how little it's contributing to California, there's a definite possibility that climate impacts will not be affected by the immediate closure of Diablo Canyon, or at least immediate within the bounds of reason.

I'm trying to find out if that's the case? So, within that, if the person who presented this particular --

(Bell rings)

MR. DAVIS: Do I have a moment or two longer? Thank you. -- has anything to say about whether or not Diablo Canyon was considered and the closure of it would change this. I would like to hear that.

Also, I'd just like to say that your -- the series for the Integrated Energy Policy Report says you will be having hearings through December. You could still have one on nuclear power. Nothing has ruled that out. I'm assuming at this point you're not.

But my personal feeling is if you took that out

because of this agreement, then you did the wrong thing. Because the agreement raises more questions than it answers. It certainly doesn't take out the original -- if you look at the scoping order for the IEPR, it says you're going to consider the seismic issues and the other issues about nuclear power. Those are more pertinent than ever.

Michael Picker's letter, about energy competing for the grid, has not been answered. That should be updated for this IEPR.

Also, the NRC hearing is this year. And the Independent Peer Review Panel just had another meeting. In the 2015 IEPR, they were still arguing with PG&E about the reality of that. There's no update for that. All of these things should be in the current IEPR draft.

And I would encourage you, you still have time to have a hearing this month, that is within your schedule, to take advantage of that time. In fact, I think there's a legal question about whether or not you're obligated, once you've put it in your scoping order, to do exactly what your scoping order says.

So, again, the question I had was will you do that? Am I right that there are no hearings on nuclear power? And, am I correct in my assumption that the Energy Commission has no position on whether closing

Diablo Canyon would have an immediate effect on global warming? Thank you very much for the extra time.

CHAIR WEISENMILLER: Thank you. I mean, the reason why I just decided, A, to have one this year, and then ultimately decided not to is, you know, we had a pretty extensive workshop last year on Diablo Canyon. And as we were actually getting very close to announcing a schedule for another one this year, is when the settlement came out.

And I thought it was going to be confusing for the public, in terms of what was our role versus the adjudicatory process at the PUC. I mean, that's really where the center of action is on the settlement. And it struck me, I'm sure a lot of people would have been quite happy to come in and talk to us, pro and con, on that. But at the end of the day, it would not be that useful to them.

And, certainly, reaching out to the PUC, and others, you know, it was like, yeah, why don't you just forget it for now, and let the focus really shift over to the PUC.

Now, having said that, in the climate context, the thing we've tried to be pretty clear on is when you look at California's greenhouse gas emission, roughly 40 percent are transportation. I think the number's 37,

but let's -- and as you know, basically, power is more like 20 percent, both in state and out. And in state is closer to about 8 percent of our greenhouse gas emissions are from power. You know, and in fact the power sector, for 2014, is 20 percent below 1990 levels. And that's even in spite of the fact, as you point out, it's been dry.

So, in terms of, you know, as we go forward, as we electrify the transportation system, there's a number of reasons why it's very important to keep the power system really, you know, zero emissions capability. But, certainly, at this stage, you know, it's really the drivers, you know, at this point, much more for climate in California is what do we do about transportation. As opposed to the power sector, as opposed to a specific part.

And, you know, we've been trying to really get people to focus on what are the greenhouse gas emissions every year for the power sector. Not, you know, looking at individual pieces of it. You know, is nuclear going up? What's the percentage renewables? What's the gas? You know, and sort of bottom line that's important is what is the greenhouse gas emissions from the power sector, which is influenced that combination.

So, bottom line, we thought it was more

efficient for people to really turn their attention to the PUC proceeding.

MR. DAVIS: Thank you for that. It's a very in-depth answer. You assumed I have a better education, in some of your answers, than I actually do. So, I --

CHAIR WEISENMILLER: But, anyway, I was just trying to say it was -- I thought about it, because we committed. Part of our commitment, frankly, was the very -- a few people came in at the last minute, last year, and said where is the chance for us to talk about the climate issues? And I was like, instead of just saying you missed the window --

MR. DAVIS: I see.

CHAIR WEISENMILLER: -- you know, tried to set it up for here. But again, I think -- anyway, I don't think we're the center of that decision at this point, and I think it would just be confusing to people to say we're having a workshop on this. Everyone rolls into this context, and not realizing that the PUC's not going to pay that much attention to what happens here.

MR. DAVIS: Well, I won't draw you into further discussion, now. But I will say, just the amount of education you expressed in this answer, to me, indicates that the Energy Commission would have been an important part of all these other proceedings by providing

information, they're not necessarily ready to collect. You are very educated on this. And I don't believe that their staff will draw up all the information that you've just provided. But you made your decision on that. I'd encourage you to change your mind and have a hearing.

CHAIR WEISENMILLER: Okay, thanks. Well, again, the good news is we're getting -- you know, with the IEPR, as I said, it's sort of like, whatever, the wheel of life. You finish one and you get ready for the next one. And, so, we are starting to do the scoping for next years. And, again, we'd have the same tradeoff next year. Just would it be better for people to focus there or here?

MR. DAVIS: I'll be fascinated to find out how you determine that.

CHAIR WEISENMILLER: Okay, thanks.

MR. DAVIS: Thank you very much.

CHAIR WEISENMILLER: Thanks.

And I think, let's see, Catherine.

MS. HACKNEY: Yes, good morning, Chair Weisenmiller, Commissioners. Catherine Hackney, with Southern California Edison. We very much appreciate the opportunity to be here to commend, not to contradict, with a little, tiny asterisk after that.

(Laughter)

So, we very much appreciate the fact that the staff has embraced the challenge of addressing not only the emerging issues, such as peak shift adjustment, we're moving on to double down on EE, EV penetration, et cetera. But also moving forward on the legacy issues, such as EMS and weather normalization.

So, in the first instance, on the emerging issue, we are so appreciative of the fact that not only staff has kind of, really, embraces a preliminary technical assessment, and the significance of a peak shift adjustment, but they did so in partnership with the ISO.

And through, in our view, you know, their agility, tenacity, and diplomacy, was able to bring in our sister in the Bay Area, the CPUC, and do so in a manner that allows us to use this preliminary assessment in meaningful ways now, for purposes of projects that have already been approved as part of the TPP, as well as looking at resource adequacy in the LCR.

So, that's a really significant effort, which moves it from academic, to real world decision making, which we very, very much appreciate.

With respect to the EMS data, what we understand, and Dennis, thank you so much for your help on this, is the data that -- the format we had received

it in, from Oasis, was aggregated to a certain extent, so there was some rounding that occurred. Which helped explain why there was a disparity between the information that you folks received, and we did.

And as Dennis indicated, we're hoping to resolve this, finally, the first quarter next year, so that we have access to the same dataset that you do. So, we're very encouraged by that.

And as Chris mentioned, on weather normalization, again, we're very appreciative for all the work that he's doing. But he did note that there are different methodologies. And, for example, you can, in the first instance, look at the highest temperature and see what the peak demand is that occurred on that day. Or, you could, instead, look at the peak demand and see what the temperature was on that day.

And in Edison's service territory, it's the latter that we have relied on, historically, because it's been a significant factor. We, historically, have experienced higher demand with temperatures that aren't at the highest level. Humidity tends to influence the demand. So, that's one area of difference.

The other would be the historic look-back period. So, the Commission, traditionally, has looked at a 30-year look back. We've looked back at a shorter

time frame. And I think it was interesting to note that in Cary's presentation, on your going forward look at climate change impacts, there's a significant potential impact in our demand forecast, and our usage. And the question might be --

(Bell rings)

MS. HACKNEY: Sorry. Can we capture that rate of change and magnitude of change perhaps a little better, if we had a shorter historical look back, as we do our weather normalization?

So, I think we would ask, in terms of a moving forward checklist, if we could include, in our ongoing conversation on weather normalization, to further refine both kind of the conditions unique to Southern California, as well as the challenges we all face with climate change.

CHAIR WEISENMILLER: Thank you. I mean, a few years ago we shortened the period somewhat. But that's always, given the changes in climate, certainly looking into that is important.

I think the other issue you run into, and I'm not quite sure where we're at, at this stage, is historically I remember, you know, basically, typically, of doing forecasting you would get data from airports. You know, and you can get like 50 years of data.

Now, having said that, people normally put airports where they expect it to be clear, and any number of things.

And, so, well, if you have weather stations more scattered throughout your service territory, while they're not necessarily public, which is a concern for us, they may be more representative of what's going on than, you know, one of the airports.

MS. HACKNEY: And as I understand it, we have provided all of our weather station data to the Commission. Correct? In response to one of your requests, so -- okay, so I've got two nods.

CHAIR WEISENMILLER: That's a good start.

MS. HACKNEY: I'll take that as a yes. All right. And, again, we just very much appreciate the opportunity to work closely with your staff, and with the other agencies, to move forward on this very important foundational effort.

CHAIR WEISENMILLER: No, that would be good. And, certainly, you know, looking at the regressions, making sure we're capturing humidity, or looking at a shorter time -- you know, I mean, the nice part about doing regressions is you have the ability to play around with things, and see what enhances the fit.

MS. HACKNEY: Right. Again, thank you so much,

appreciate it.

CHAIR WEISENMILLER: Yeah, yeah, great.

Anyone else in the room? Anyone on the phone?

MS. RAITT: I'll just say, if anyone on the WebEx wanted to make a comment, please use the chat function to let our WebEx coordinator know? So far, we don't have any.

If we'd like, we could open up the phone lines and see if there's anyone on the phone, who would like to make comments. If you're on the phone, please mute your line, unless you wanted to make comments.

Again, I'll just ask you to mute your line, unless you want to make comments.

No, it doesn't sound like we have any.

CHAIR WEISENMILLER: Okay. Well, again, I'd like to thank everyone for their participation. Certainly looking forward to your comments. And, also, again, certainly looking forward to sort of pulling this together and then marching on to next year. So, thanks.

(Thereupon, the Workshop was adjourned at 11:33 a.m.)

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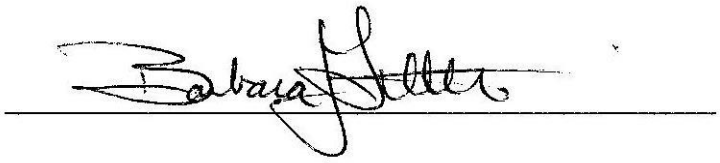

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