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2018 California Energy Demand Forecast Update

Transcript of Proceedings

California Energy Commission

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10:00 a.m.

Brittany Flores, CSR 13460

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PROCEEDINGS:

December 6, 2018

MS. RAITT: Welcome to today's IEPR commissioner workshop on the 2018 IEPR demand forecast. I'm Heather Raitt, the project manager. I'll quickly go over some housekeeping items before we get started. Restrooms are in the atrium at the door to your left, and if there's an emergency, we need to evacuate the building. Please follow staff across the street and diagonal to Roosevelt Park. Today's workshop is being broadcast through our WebEx system, so please be aware that you're being recorded. We'll post an audio recording on the Energy Commission's website and a transcript in about a month. There will be an opportunity for public comments at the end of the day, and we'll limit comments to three minutes each. For those of you in the room, who would like to make a comment, go ahead and fill out a blue card and you can bring it to me, and we'll have you come to the center microphone when it's time for you to make your comments.

And for WebEx participants, I have some instructions for you. You can use the "raise your hand" feature that WebEx provides if you want to make a comment. And we'll call you during the public comment

period. And using that same feature, the "raise your hand" feature, you can also lower your hand if you choose to withdraw your comment, and you can use the chat function if you need to contact the WebEx coordinator with any questions, or they can relay your message to staff or presenters at the appropriate time, but we will hold comments to the end of the day. For phone-in participants, we'll open your lines after, after the end of the meeting. And all the materials for the workshop are at the entrance to the hearing room and posted on the website. And written comments are welcome and they're due on December 20th and the notice provides all the information for making written comments.

And with that, I'll turn it over to the dais for opening remarks. Thank you.

CHAIR WEISENMILLER: Great. Thank you. I'd like to thank everyone for being here. Obviously, one of the keys roles of the Energy Commission is demand forecasting. Our forecasting is used by the other stages of planning. So I want to welcome Commissioner Randolph and Neil here today as part of this process. It's certainly important not only to us but the other agencies. So it's important to get it right. So certainly looking for the opportunity. Staff's put a lot of time in, sort of, upgrading the models and the

data this time, and we certainly appreciate the hard work and looking forward for the rollout today and certainly encourage everyone to help us really dig into it, and there you know, certainly will be some issues or problems, we'd like to find them now. So anyway, thanks again.

COMMISSIONER HOCHSCHILD: Good morning, and, and thank you all. I -- I'm also just really pleased we have all five of us on the dais together, which has not happened much for these. So -- and welcome your colleagues as well and thank staff for putting this workshop together and look forward to the discussion.

COMMISSIONER RANDOLPH: Thank you very much. I really want to thank CEC commissioners for their leadership and CEC staff for all of the work they have done on the -- on, you know, tweaking this process and, um, making the monthly forecast part of the IEPR process and, and really excited to be able to have, um, sort of, public input and transparency around these forecasts that inform our, um, resource adequacy planning. So, um, I really look forward to the detailed discussion, um, and thanks for inviting me to participate.

MR. MILLAR: Hello. It's Neil Millar with the California ISO. I also just wanted to, a, say thank you for the opportunity to participate in the session today, and B, I also just wanted to emphasize how important it

is for the ISO both in our short and longer term planning activities. The emphasis on forecasting work and the importance if there's broad agreement on the principles behind the forecasting that's so critical to us, and we also really appreciate the amount of extra effort both commission staff have done through actually in advancing the coordination between the agencies.

Thank you.

COMMISSIONER MCCALLISTER: Great. So we have a lot to talk about today, so I won't take much time. But I want to -- this is Andrew McCallister, and I want to thank Neil -- and Commissioner Randolph and Neil Millar for coming, because our sister agencies in this are just critical and just highlight that as we move, you know, forthrightly, kind of, into the, the big data era, you know, the digital age fully and update our tools. The overarching goal here is to, as Commissioner Randolph alluded to, increase the transparency and the, sort of, both analytically and process-wise for the forecast. You know, we have access to immense amounts of data and this is a -- really a top level responsibility of the Energy Commission. And certainly, if we want to really do justice to this distributed energy world that we live in, we have to really dig in and develop the forecast itself to be much more

granular, much more temporally aware, and really focus, be able to drill in, you know, to different, you know, slice and dice the data in much more focused ways. And so this, kind of, reflects the bigger -- the bigger project that we have at the Energy Commission to, to leverage all the great information that we now have in today's day and age. And the forecast really has, I think, has a heavier burden than ever on it to inform the more -- the processes, which are, kind of, ever more complicated and localized at all of the agencies. And so, you know, I think having, managing a process that has public input, and it really has a lot of back and forth with various stakeholders to improve the transparency and rigger of it. Not that it hasn't been, you know, adequate in the past, but I think just the complexity of it just demands that we do that now. But I think to get to a usable really robust outcome, it's essential to have this back and forth not only among the agencies but also with the stakeholders, and I want to just thank Siva and your predecessor, Silvia, for sort of setting this up and also Cary and Nick and really the whole team we have got, because I think we've built a great team to carry this process forward.

So with that, I'll ask my fellow commissioners -- no comments? All right. So Heather --

MS. RAITT: Great. So our first speaker is Cary Garcia from the Energy Commission to give an overview of the forecast.

MR. GARCIA: All right. Good morning, commissioners and everybody else. I'm Cary Garcia. I'm a demand forecaster in the energy assessments division. I'm on the tail end of a cold. So if I sound a little muffled or cough periodically, don't mind me, though. Try to spray this whole area with Purell later on.

Excuse me. Miss a call once in a while, so I have to turn my ringer on, and I forget to turn it back off.

All right. So we're going to get into the forecast update overview. Before I get started, though, just a little bit of background on the forecast update itself. So typically, we've done just our traditional IEPR forecast where we do it every two years, but, you know, given some of the stakeholder needs, um, transmission planning process, um, we -- we've decided to incorporate an update in between our annual IEPR forecast. And so typically, we will simply update the historical consumption sales and update the economic and demographic information. But given the changes in electric vehicles adoption, the changes in PV that are occurring, we've decided to incorporate those updates as

well. Typically, we leave those, you know, as they were in the previous IEPR forecasts, but given the new information that we have and the changes in those particular sectors, we include those as well. So this will -- this update now will include the changes for the economic and demographic drivers as well as an updated EV forecast and PV forecast as well.

So just a little bit of background on the update process, itself, particularly the economic portion. So what we're really doing here is just re-estimating the econometric models for our major sectors that we have; residential, commercial, industrial, manufacturing, the mining sector, which is resource extraction, construction, ag, and then transportation, communication, utilities, or TCU, and then street lighting. So we run those models, and we're basically running the econometric models with the previous data that we've had in the 2017 forecast. We run them again with the newer information, and then we apply the percentage differences in the econometric forecast, net up the post processed impacts that I mentioned. So EV being something that's handled separately as well. So really, it's, kind of, up lighting that baseline consumption forecast.

And as I said, electric vehicles is going to be

Re-estimated, along with self-generation, and then we have new rate forecast as well. But as far as energy efficiency, we really -- in terms of our additional achievable energies, we're really just adjusting incremental 2017, and then moving that out towards 2018 and continuing on with that energy savings. Then I should also add, we'll -- we do have an update as far as the self-generation is concerned to the additional achievable PV as well, but you'll see it's a small change in comparison.

So our scenarios are the same as before. We have a custom scenario that Moody's developed for us for our high scenario that give us a better spread on that high outlook. The mid demand scenario is Moody's baseline, and then our low demand scenario is below trend, long-term growth, but that remained the same since 2018. Just simply updated with the new information we have for the scenarios.

So we can do our comparison here to the economic drivers. So looking at per capita income on a statewide level, we see that down a little bit in comparison to 2017. Population goes up just a tad but relatively flat in comparison to 2017. Households also down. Gross state product and manufacturing and commercial employment. And you'll see this later on in terms of

population still remaining strong, and even though on a statewide level, household went down, you'll see later in the presentation in the afternoon that some of the planning areas, households still continuing to grow while population, um, um, stays relatively flat. But overall, you see commercial sector going down. So you'll see commercial sector consumption go down but residential consumption still remains pretty strong.

So looking at some of the -- this is actually a correction here. On the top there, it should say, "Statewide per capita income" not "Personal income" in a raw amount. But you can see the comparison here looking at that light blue line in the middle. There's really not a whole lot of change compared to our mid case that we have now, which is that grey line. They're pretty much stacked onto each other, but in the end they're only small fractions of a percent lower in comparison. Looking at manufacturing output, we do see a slight decline in comparison particularly towards the end, but you'll see this in the economic information. What, sort of, happens with Moody's adjustments is that the growth, kind of, sped up in the near term, but then it, kind of, bottoms out in the end. So we see this, kind of, um, you know, what they projected in the near term, kind of, move a little bit closer. So you see a little bit of

growth, but then in the long run, you end up seeing lower overall growth, and you see this in manufacturing. We see something similar in commercial. If you look at that gray line right there, you see that, kind of, bump up. So it moves a little bit sooner, but then it declines. And there's lots of -- there's more decline in that in comparison to 2018 -- or sorry -- the 2017 forecast. So we're about 1.37 percent lower. And you'll see this play out where I show the commercial -- when I show the function forecast with the planning areas. Gross state product is down. This is mainly a driver for, like, the industrial sectors. But that is -- sorry. It's gross state product, in this case, is higher. But the trend is definitely not growing as fast.

So just real quick, I typically would just jump straight into the statewide results right now, but I think it makes more sense for us to get into the EV and the PV as well before we move on to, sort of, set the context for the statewide results. But if there's any questions on the economic information, I'm be happy to take them.

I think the biggest take home message is just things are a little bit lower in commercial sector drivers, but the residential stays about the same.

MS. RAITT: Thanks Cary, So next is Sadar Konala from the Energy Commission.

MR. KONALA: Good morning, Commissioners. Before I start with my presentation, I would just like to thank -- he's my predecessor in this position, and he's been very helpful in me getting up to speed on the PV forecasting models.

So before I get started with the PV forecast, I just wanted to go over our scenarios just briefly because for our forecast, they're defined by electricity demand. But in terms of PV, the -- it's, kind of, inverted. So when we are projecting high electricity demand, we're assuming low PV adoption. So you'll see a word that says, "high," but the actual value will be low. Similarly, in the low electricity demand case, we're assuming a high PV adoption. So this gets a little tricky even for me sometimes. So I just want to clear the air just before I go through the forecast.

Okay. So this is a slide that I presented before, but I just wanted to remind everybody how we do that PV forecast. So we collect data in four main areas that includes installed capacity. We also collect data in economic index and demographic data, specifically, residential building count and commercial floor space. We also have fuel price forecast from the

supply analysis office specifically in electricity rates, and we also, um, look at PV installation costs, and using all of this data, we feed our PV models. We have two of them, the residential sector model and the commercial sector model. Then we also have a third model, which is essentially all other sectors. And while in the residential and commercial sector, we do use a predictor model. The third model is just a trend analysis. So using these three models, we get a statewide forecast for installed PV capacity, and then we use assumptions of capacity factors to create a forecast of energy generation from behind-the-meter PV.

So just a quick discussion on the updated inputs for the 2018 forecast. So we updated installed PV capacity through 2017 for the IOUs and SMUD and for some of the smaller POUs. We really didn't have updated data, so we retained the 2016 data. In terms of demographic and economic data, again, we updated the forecast for residential building count and commercial floor space. We also had a new forecast for electricity rates, and the big point from this is that electricity rates, especially in the residential sector, tended to be lower in the 2018 forecast than in the 2017 forecast. We also updated PV installation costs. We revised a few of the historical years and also added 2017

values.

So a quick overview of historical statewide PV installations, as of 2017, we had about 6,700 megawatt hours of PV installed statewide and that was about 888,000 of installations that are known. And looking forward to the forecast, we anticipate that by the end of the year, there's going to be about 8,000 megawatts of installed capacity, and we estimate that installations will reach about 950,000. I also want to go over -- sorry. Um, there was a comment. It's megawatts. Not megawatt hours. I misspoke. Sorry.

So I just want to go over also where the installation data comes from, because it comes from a variety of sources throughout history. So initially, the data we started collecting from the emerging renewables program, and as other data sets were available over time, we started using those. So here is the timeline of the different data sets. So over time, we've used also the S chip or the self-generation incentive program, California Solar Initiative, new Solar Homes Partnership, SB1POU, and more recently, we've been using the IEPR Form 1.8, and for the 2017 forecast, the updates and installed capacity came from the NEM interconnection data set published by the CPUC.

So I also quickly wanted to go over how some of the inputs affected the PV forecast, a high level overview. So, um, building -- residential building count, we saw was lower throughout the residential sector in all, all three scenarios actually, and this had a negative impact on the PV forecast itself. Electricity rates in the residential sector were also lower in the 2018 forecast compared to 2017. So this also has a negative impact. In the commercial sector, floor space -- our projections of floor space tended to be higher. So these, these -- this chart represents the average across statewide for individual utilities. You might see slight changes or a reverse on the signs, and I'll go through those as we go through the energies and utilities. Electric rates were mixed in the commercial sector. They were lower in the high electricity demand case but higher in the lower electricity demand case. There was also one methodological change that I want to talk about briefly.

In the high demand case for the residential sector, we revised how we did the adoption of PV systems compared to the 2017 forecast. So just a little of historical context. So in the 2017 preliminary IEPR forecast, staff used -- bill savings metrics to translate bill savings to adoption for IOUs and SMUD, and

this is specifically in the residential sector. However, after the presentation for the preliminary forecast, CEC management requested that a wider range be shown in scenario results. This led staff to consider the use of another metric for the high demand case. Specifically, staff used a payback period based on RW Beck, which gave a much lower adoption rate. But due to staffing and timing constraints, the revised 2017 IEPR forecast applied a simple ratio adjustment to translate adoption between the two metrics. For the 2018 IEPR forecast, we used the same payback metric, RW Beck, but we directly applied it to the high demand case. And when examining the difference between the 2017 IEPR and the 2018 IEPR, the ratio adjustment used in the 2017 revised forecast compared to the ratio used in the 2017 IEPR forecast, 2018 forecast looked to a much greater -- I'm sorry. Let me restart that.

In examining the difference between the 2017 IEPR and the 2018 IEPR, the ratio adjustment used in the 2017 IEPR led to a much greater downward adjustment than using in the payback curve in the 2018 IEPR.

So -- okay. So if there aren't any questions on this, I will get moving into the actual forecast results.

Okay. So here's a chart showing installed

statewide capacity, both historical and forecast for the State of California. As I said earlier, in 2017, we, we estimate that there's about 6,700 megawatts of installed capacity. In the mid case in 2030, we anticipate that this will increase to 20,200 megawatts, an increase of about 1,100 megawatts. In the low electricity demand case, we anticipate growth going up to 25,600 megawatts, which is a decrease from the 2017 forecast of about a thousand megawatts, and in the high electricity demand case, we forecast 14,950 megawatts, which is an increase of about 3,300 megawatts from the 2017 forecast. All of these numbers are -- of megawatts are in AC. So they will be lower than the DC name plate rating that you often see with systems.

So the changes in the 2018 forecast are driven by two different underlying trends. So commercial additions in the 2018 forecast were higher across all three scenarios, but in terms of the residential sector, additions were higher in the high scenario because of the explanation about the change in methodology I provided. In the -- in the low, low demand case in the residential sector, additions were actually lower, and this was due to, um, a lower growth in residential housing count and -- as well as a lower growth in electricity rates. And finally, in the mid case,

residential additions were essentially the same as, um, the 2017 forecast.

COMMISSIONER RANDOLPH: Can I -- can I ask a question. This, kind of, goes back to input.

MR. KONALA: Yeah.

COMMISSIONER RANDOLPH: Can you tell me a little bit about the rates input, sort of, where, where that comes from and --

MR. KONALA: Yeah. So the rates are an exogenous input into the forecast developed internally at the CEC, but I receive it from another office. Um, the, um, analyst that does the rates has a dialog with the individual utilities to come up with a rate forecast.

COMMISSIONER RANDOLPH: Okay. And so did the -- so is there a particular reason why they were showing lower rates in '18 than '17?

MR. KONALA: Yes, and she provided an explanation yesterday, but I can't remember off the top of my head. I know --

COMMISSIONER RANDOLPH: Okay. I can follow up.

MS. MARSHALL: We do our internal rate projections and use that with a combination of data that's submitted by utility. They submit their revenue

requirement projections, and we use that in conjunction with staff assumptions on wholesale energy prices and some other inputs. So for this forecast, the things that -- we did a limited update to update it to current electric rates and revenue requirements, um, and to current wholesale procurement prices. Our last forecast included an increase in natural gas prices that did not occur. So the -- our forecast of wholesale price for this rate forecast is lower. So that's one factor, and the other is using some -- and FUC finally sent utility advice letters on the impact of 2017 Tax -- Reform and Jobs Act I think it's called, lowered revenue requirements for the utilities. So the rates are still increasing, but they're increasing at a lower rate.

COMMISSIONER RANDOLPH: Okay. Okay. That makes sense.

CHAIR WEISENMILLER: Okay. For the record, you should identify yourself.

MS. MARSHALL: Lynn Marshall, Energy Commission staff.

CHAIR WEISENMILLER: And certainly, Commissioner Randolph, I don't know if it would help for her to connect with the PC staff. We could certainly, she would be quite happy to do for sure.

COMMISSIONER RANDOLPH: Yeah. And that

explanation made a lot of sense. Thank you so much.

MR. KONALA: Okay. So I also provided a -- wanted to provide a brief overview of the breakdown of where the capacity additions occur, um, breakdown by planning area. So, um, actually not a whole lot of new information, but I did want to show that, um, the changes from the 2017 IEPR and the statewide results. So again, there was a large increase in the high demand case, a decrease in the lower demand case, and a slight increase in the mid demand case in the installed capacity compared to the 2017 forecast. Here is a chart showing energy and gigawatt hours, and essentially, the numbers are very similar. Energy is determined by capacity. So the same trends are true.

So I also wanted to give an update for the AAPV forecast, and I'll start with giving a brief explanation of what the AAPV forecast really is. So AAPV, which stands for Additional Achievable Photovoltaic adoption accounts for PV system requirements for new homes, as specified in the 2019 Title 24 standards, which were finalized this week I believe. So in the baseline forecast, a certain percentage of new homes adopt PV systems. Um, so the AAPV is just defined as difference in PV adoptions for new homes due to the 2019 Title 24 regulations versus what new home PV adoptions were already in the baseline forecast. So, um, some of the

assumptions for the AAPV forecast that we used were the same as the 2017 IEPR. So we have an expected level of compliance of 90 percent in the low electricity demand case, 80 percent in the mid electricity demand case, and 70 percent in the high electricity demand case, and our assumptions about average systems size -- also remain the same.

Here's a slide slowing some of the results for the AAPV forecast in 2030. Um, well, I'm not going to go through each of the planning areas. I do want to note that AAPV is actually higher in the high demand case and lowest in the low demand case. Um, and this is because the, um, the growth in PV in the baseline forecast is so much greater in the low demand case than the high demand case that it is eating into AAPV. So the AAPV, the difference of 90 percent, 80 percent, and 70 percent isn't a big enough difference so that the growth in the baseline forecast shows the lowest AAPV in the low case.

COMMISSIONER MCCALLISTER: Can I ask you a quick question about that?

MR. KONALA: Yeah.

COMMISSIONER MCCALLISTER: So just to be clear, what -- in terms of the solar requirement for the new standards that was, you know, approved, adopted by

the building standards commission yesterday --

MR. KONALA: Yeah.

COMMISSIONER MCCALLISTER: -- what's the plan for moving, you know, that from AAPV into the baseline going forward?

MR. KONALA: Yeah. Going forward, it will be part of the baseline. We will, again, revisit whether the assumptions we have used in 2017, and 2018 forecast are valid going forward into 2019. And if not, we will change those assumptions, but in terms of the methodology, with the AAPV portion of the forecast will be fed into the regular baseline forecast.

CHAIR WEISENMILLER: Was that for this year or for next year?

MR. KONALA: For next year.

CHAIR WEISENMILLER: Okay.

MR. KONALA: AAPV is separate for this year. As we mentioned in the workshop earlier this year and a lot of that has to do with AAEV as well. The plan is to role AAPV and AAEV into the forecast for next year

One other point I'd like to make is that the AAPV results in the 2018 forecast were lower than our projections in the 2017 forecast, and this was caused by two different factors that, kind of, squeezed the AAPV forecast in the 2018 IEPR. One of the reasons is, in

general, a higher baseline forecast and the second reason is that household growth was lower in the 2018 forecast. So, um, both, both of these trends are just squeezing the AAPV forecast this time around.

Okay. So I'll be moving towards individual planning area results.

CHAIR WEISENMILLER: So let me ask --

MR. KONALA: Yes.

CHAIR WEISENMILLER: Well, let me ask two, two general questions. One of them was -- one of the reasons for doing these annual updates was that historically, our forecasts for PV were too low. Last year, the industry reaction was that our forecast was too high.

MR. KONALA: Yeah.

CHAIR WEISENMILLER: That we had not taken into account the impacts of the PUC net metering decision. So I -- how did -- how did we do, you know, relative to what was going on in the market as opposed to what we were forecasting?

MR. KONALA: So in general, incorporating the NEM 2.0 information did lower the forecast from what it would have been, but the trends are still pushing for the adoption of PV. So overall, the forecast is slightly higher from 2017 to 2018, but if

you look at adoption rates; they would have been higher if it was just tiered rates or averaged rates instead of time of use rates. So the rate structure is definitely muting the growth of PV over time.

CHAIRMAN WEISENMILLER: Okay. My other question was originally the inland model had a not particularly inspiring R squared. I think it was like point five or something. What -- how good is -- are the regression results now in terms of goodness of fit measures, coefficients?

MR. KONALA: Um, we don't really do an R squared, so I don't have that information.

CHAIRMAN WEISENMILLER: Well, if you can check on that --

MR. KONALA: Yeah.

CHAIRMAN WEISENMILLER: -- statistical goodness of fit, that would be good to know.

MR. KONALA: Okay.

CHAIRMAN WEISENMILLER: Go ahead. Sure. Go ahead.

MR. FUGATE: In speaking with the demand analysis office and I just wanted to comment on that. So we haven't prepared anything on the -- in real model results. We're still having preliminary work on that, and our intention is to, sort of, look at that for the

2019 IEPR forecast.

CHAIR WEISENMILLER: Okay.

MR. FUGATE: This is something we'll be workshopping on next cycle.

CHAIR WEISENMILLER: Okay. Good. Thanks.

MR. KONALA: In the DAWG meeting NREL provided their preliminary results, but they emphasized they were extremely preliminary. So essentially, what we did was we looked at the raw results.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MCCALLISTER: I'll add one more question.

MR. KONALA: Yeah.

COMMISSIONER MCCALLISTER: So go back to your slide six, all the different data sources that you used.

You know, in past years, we have, sort of, you know, had to deal with some of the inconsistencies with those data sets and, kind of, making sure they were apples to apples and apples. Have you -- well, particularly, with the Form 1.8, but, you know, the other databases, CSI, et cetera, how much ongoing work is there ensuring the compatibility of all those data sets and, you know, dealing with all differences in data quality and things

like that?

MR. KONALA: Um, we do look at the different data sets, essentially, to make sure that when we're combining the different data sets that there isn't overlap. But, um, overall, we feel that if there's reliable source. So if you look at the NEM interconnection data, that actually goes back historically through 1996 or 1998 or something. So when we look at the other data sets and add them up, it's similar or slightly -- um, it's slightly higher than what NEMN is showing. Um, so if while -- you look at any individual year, it might vary a little, like slightly up or down. Overall, it's very comparable to NEM but slightly higher.

COMMISSIONER MCCALLISTER: So you're comfortable with being able to combine all these data sets?

MR. KONALA: The reason why we don't just use NEMN by itself is because we feel that -- so if you look at the IEPR Form 1.8, which is the most complete data set we've had in recent years, NEM tends to underestimate the values in the IEPR Form 1.8 by about three percent every year.

MR. MCCALLISTER: Interesting. And then following up on some of the factors that influence, you

know, which direction it goes from year to year, has there been any shift in the cost production trajectory that has played a role here in terms of new construction or just solar cost in general?

MR. KONALA: Um, so there's been a slight ridge downward in the cost, but I don't know that number specifically off the top of my head.I can tell you that we did do a revision of historical cost lower compared to the 2017 forecast and that was just, um, doing work analysis of the information and the NEM interconnection database. I do want to point out that our estimates of cost are higher than other entities, and that's just because the data from the NEM interconnection database is what we use. So whatever our analysis of that database comes up as is information we can use.

COMMISSIONER MCCALLISTER: In any case, it's calibrated to -- I mean, the models are calibrated to what actually happened historically.

MR. KONALA: Yeah. Yeah, we can do a calibration of the historical.

COMMISSIONER MCCALLISTER: Yeah.

MR. KONALA: Okay.

COMMISSIONER MCCALLISTER: Great. Okay. Thanks.

MR. KONALA: All right. So moving on to

individual utility and planning area forecasts.

Okay. So here's the forecast for PG&E's planning area. In -- so, um, so far, I've essentially presented capacity, but going forward, I'm going to present energy generation systems, but the two forecasts are related. So the trends in capacity are essentially shown in the energy generation slides as well. Um, so, um, in 2017, um, we estimate that behind-the-meter energy systems generate about fifty-one -- 5,100 gigawatt hours of energy. In the mid case by 2030, we believe this will be about 16,300 gigawatt hours, which is slightly higher than the 2017 forecast. In the low electricity demand case, we forecast that energy generation will be about 22,000 gigawatt hours, and in the high electricity demand case that it will be around 12,000 gigawatt hours.

Um, so the new mid case is about 8.5 percent higher. This increase comes from more installations in the commercial sector. A lot of this increase comes from actual adoptions that we saw in 2017, which were about 30 percent higher than what we forecast in the commercial sector. Um, and this increase in the commercial sector forecast overcomes a forecast of slower growth in the electricity rates in the commercial sector. There is a slight decrease in the residential

adoption in PG&E's territory. However, this is limited to the low and mid demand cases, and the high demand case adoption is higher at more than 25 percent compared to the 2017 forecast, and this is just due to methodological changes that I had specified earlier.

Here's a chart showing the different sectors in the mid case. The main thing I want to point out is that while the residential sector remains the largest portion of forecast of PV additions, a lot of the growth in the early years was driven by faster growth in the residential sector, and then growth in the residential sector does slow down over time, and this is just because we're, kind of, reaching a saturation point in -- with residential systems. That's why the AAPV value's actually not significantly higher than the baseline forecast. However, growth in the commercial sector does accelerate over time.

Okay. So now, moving on to southern California Edison. Um, for 2017, we estimate that behind-the-meter PV generated about 3,700 gigawatt hours. We forecast that to go to 12,100 gigawatt hours in 2030. In the low electricity demand case, we project that to go over 15,000 gigawatt hours. In the high electricity demand case, we project that to be about 9,000 gigawatt hours. So for southern California Edison, the new mid case is

comparable to the 2017 IEPR. The commercial sector does have a higher starting point in 2017 similar to PG&E. In this case, it's higher by about 20 percent in 2017 compared to our previous forecast. The low case is lower, um, in the 2018 forecast, um, by about 14 percent. This is driven primarily by lower adoptions in the residential sector, which is due to much lower growth in electric rates compared to the 2017 forecast. The growth is actually lower by about two percent a year compared to the 2017 forecast. In the high case, the growth is -- the growth in PV adoptions is higher by about 38 percent, and this is driven by much higher adoption rates in the residential and commercial sectors.

So for the sector forecast, essentially, again, residential is a primary driver in the growth of PV admissions, but unlike PG&E and foreshadowing unlike the other POU's, San Diego Gas and Electric, we continue to see robust growth in the residential sector over time, and this is primarily because unlike the other IUOs, southern California Edison starts at a lower saturation rate and it doesn't -- it doesn't hit the saturation of the other IOUs in the forecast period. So it just keeps growing at a brisk pace.

Okay. Moving on to the last IOU, San Diego Gas and Electric. We estimate that 2017 generation to be

about 14 gigawatt hours. In 2030, this is going to grow to close to 4,000 gigawatt hours. The main thing to point out is that all three demand cases in 2018 are higher than the 2017 mid case. This is driven by much higher commercial sector additions in all three cases. Adoptions were higher in 2017 actual compared to the forecast of commercial additions in 2017 in all cases. Electricity rates also grow faster in the commercial sector in 2018 for San Diego Gas and Electric compared to the 2017 forecast. So, a higher initial base of adoption and a higher forecast growth of electricity rates essentially drives a higher growth in overall commercial additions. The residential forecast is higher in the high demand case and lower in the low demand case. The lower growth in electricity rates and household growth in the low demand, essentially, is the reason for the low adoption in that scenario.

In looking at the sector forecast, it's a similar graph as that of PG&E. San Diego actually has -- currently has the fastest growth of PV adoptions, and they're also the ones reaching the highest saturation point in the residential sector. So after about the early 2020s, you see that growth in the residential sector is muted, but it's, um, it's, kind of, overcome by much more increased growth in the commercial sector.

Okay. So moving on to the, um, two big POUs in the state. Here's the forecast for LADWP. So for LA DWP, the latest historical data that we had was from 2016. So essentially, the 2018 forecast had the same installations as the twenty -- as the 2017 forecast. But -- so any changes that you do see is related to other inputs such as residential and building count and electricity rates and PV installation costs. Overall, the mid and low cases were similar to 2017 forecast, but the high case was slightly higher. So, higher residential -- higher residential adoption did occur in all three cases, and this is driven by a higher forecast for electricity rates in the 2018 IEPR update compared to the 2017 IEPR. This was muted by lower commercial adoptions overall. And in terms of the sector forecast, you can see that, essentially, the residential sector dominates to a much higher percentage in LA DWP territory than the other IOUs.

Okay. So moving on to SMUD. For 2017, we forecast that there are about 274 gigawatt hours of energy generated from by behind-the-meter PV. In 2030, we forecast this increase to 748 gigawatt hours. Overall, the new mid case is about 20 percent higher than the 2017 IEPR forecast. The low and high cases are also higher by about eleven percent and 60 percent

respectively. This is driven by much higher commercial sector forecast in the -- than in the 2017 IEPR. And this is driven by a higher starting point in the 2017 installations compared to our 2017 forecast. In terms of the residential additions, they were higher in the high case, but they were similar to the 2017 forecast in the low and mid cases.

So this represents the last slide I have. The big takeaway from all of the different slides is that, um, the changes in the forecast were driven by input changes, and in the residential sector, we had lower electricity rates overall and lower growth and building count, where in the electricity sector, both rates and projections of floor space were mixed. So we saw some utilities have higher production and some utilities have lower projections.

And finally, in the high electricity demand case, we generally saw higher projections because of the methodological change and since -- at least in the residential sector, our mid electricity demand case is just an average of the low and high. This methodological change in the high electricity demand case also drive a slightly higher mid electricity demand case as well.

So I'll -- sorry. I forget about the final slide,

but I covered it. Okay. So that's all I have unless you guys have questions.

All right. Thank you.

CHAIR WEISENMILLER: Great. Thank you.

MS. RAITT: And next is Aniss Bahreinian to talk about the electric vehicle forecast.

MS. BAHREINIAN: Good morning, commissioners, stakeholders. My name is Aniss Bahreinian, and I'm presenting the PEV forecast update for this -- for 2018. I should also mention that the scope of the update was limited to light duty plug-in electric vehicles, and this is repetition of the slide that we showed in the last workshop, and this includes now the third quarter. As you can see here, between 2014 and 2017, the sum of the shares of green cars remains almost the same. If you add up -- considering green cars as hybrids, PHEVs, and PEVs, and they're almost the same, around 9.5, 9.6, but as you can see here for the first time, this sum has grown to 11.2. So we see a significant growth in the market, and most of this growth in the third quarter is due to the sales of Tesla's Model Three. Many of you have heard about that. So there were -- Tesla increased their production capacity, and then managed to catch up with their demand. And the result is a significant increase in, in

PEVs in the third quarter, and we expect that to continue through the fourth quarter. And this -- as -- if you also look at the graph and the table, you will see that starting in 2014, um, PEV sales -- and mid 2014 -- even though we had a decline in gasoline prices, PEV sales started to go above the PHEVs. That was in mid 2014. And as you can see here, actually that trend has continued to. So we continue to see more PEV sales than the PHEV. This is consistent both with our survey. Our survey also shows that consumers have higher preferences for PEVs as compared with PHEVs. As you can see the market supports that, too. Um, we also see that in 2018, for the first time, PEV alone is catching with hybrid. So you can see that the share is about 4.1 percent for PEV versus the same number, 4.1 percent, for hybrid vehicles. So plug-in hybrid vehicles are actually catching up and exceeding -- the sum of the two is actually exceeding the hybrid sales.

There are a couple trends that we need to be aware of. One of them is the share of the light trucks in the new vehicle sales. As you can see here, light trucks, represented by the red line for the retail, is exceeding the passenger car category in 2017. And in this slide with the third quarter, we see the continued growth of light trucks. That's important for us because

what that point out is that we need to have more in this car category for the PHEVs and EVs in order for the market to gain momentum. We have -- in our forecast of makes and models for PHEVs, we are showing increase numbers of announcements in the PHEV in the light truck category. And also, there's a recent company who has come to the market, and they are building -- they're focusing specifically on this category. So we're also going to have more EVs in this category with the new announcements that are coming to the market.

So you can see here that retail cars are, are going down by 10.5 percent and retail light trucks are going up by 5.6 percent. I should notice here -- I should bring this to your attention that what we mean by "light truck," it includes crossover SUVs, SUVs, pick-up trucks, and vans. You can even see it on streets. The other day, I was looking at a police officer who stops somebody in the traffic. You could see that the police officers who used to have these large cars, they now have crossover SUVs. So it is even evident on the roads.

MAN IN AUDIENCE: What is a light duty car?

MS. BAHREINIAN: Light duty car for our purpose is anything that is less than 10,000. So anything with a gross weight less than 10,000, we

consider that light duty vehicle. Anything above that weight category goes into the mid and heavy duty vehicles.

That was the, um, statewide shares, but we should notice that there are differences in between different regions of California. As you can see here, it seems like southern California has a faster rate of decline in cars and a faster rate of the increase in light trucks. You can see the difference between northern California and southern California in this graph explicitly.

So also, I should say that in different countries, you also have different shares. So you may have an increase in light trucks in the US, but in some other countries, that could be actually diverse.

Another trend that we should pay attention to is how many new vehicles are excelling. There has been a decline in new vehicle sales in 2018. So we see a decline. Some people refer to that as the car recession has already started, but in any case, what we see here are the sales of vehicles in the market in California. We're showing the used vehicle sales and the new vehicle sales, and you can see that there's a decline in both categories. Both used vehicle sales and new vehicle sales are declining. However, there's a smaller decline, a much smaller decline in the used vehicle

sales. So this is going to result -- if you look at the last column, it is percentage of vehicles bought and sold in California that is new. So these are the new vehicle sales, percent new, and you can see that there's also a decline in that. It is going down from 32 percent in 2017 to 31 percent in 2018. This is important again for new technologies in general including EVs and PHEVs because most of these are new technologies, and they would go up. They would be more, um, correlated with the new vehicle sales. So with the decline in the new vehicles sales, we could also see a drop, but interestingly, as you can see in the first graph, PHEVs and EVs are actually growing.

COMMISSIONER SCOTT: Aniss, a clarifying question for you on that last slide. It says that it's, um, year-to-date through September. So is, is the -- are the 2017 numbers for the entire year and the 2018 numbers are just through September?

MS. BAHREINIAN: Both of them are the same.

COMMISSIONER SCOTT: Oh, okay. So just it's -- okay. Thanks.

MS. BAHREINIAN: In order to be able to compare.

COMMISSIONER SCOTT: Right. Just checking.

MS. BAHREINIAN: So with this, we are going

into our forecast actually. So all other ones are actual data that we are seeing in the market and the market trends. We should also notice that they're forecasting overall. They are also forecasting a recession coming in 2020. So there's going -- there could be further decline in vehicle sales in that time.

This one, this graph shows our light duty vehicle population. And as we can see here -- look at the top two lines. These are our mid case and our low cases. I should -- and this clearly shows that our mid case is not the average of the high end. They each have their own characteristics and their own data. We use different inputs for different, different cases here.

Notice here that we are using the same household populations. We only had two population scenarios, and we used one of them for the low and the mid case. And we used the other one -- the higher one obviously -- for the high demand case. Notice how close they are. They are almost the same. If we – if we had to really blow up the graph in order to even see the difference in these lines as we can see in this graph. So they are pretty close, mid case and low case, but the increase in population, household population, or the higher population -- household population in the hunt case is mainly responsible for the higher numbers of light duty

vehicle populations in the high case.

So what do we do. In order, as you can see here, our light duty vehicle population. We're pretty close to each other. So we have to diverge them. How do we do that. We try to capture some of these uncertainties that exist in the market with different scenarios that we have for PVs. And those different scenarios, as you will see in the later slides, are going to create a wider range in our forecast of PEVs. This shows -- this shows all the -- all the relevant or the important or key input into our PEV forecast. And as you know -- many of you know, we are using a lot of data in order to generate our forecast. This is only a portion of the data that we are using. We, of course, are using the household population, fuel prices, and income that the rest of our office is using in generating forecast of demand, but when we're focusing on the PEVs, we are looking at some of these key inputs into the PEV scenarios. The first one is, of course, the consumer preferences. With -- for the consumer preferences, in the low case, we make the assumption that consumer preferences are going to remain constant for the PEV. They don't change for the ZEV vehicles in general, and they don't change, and they are remaining the same. However, in the reference high and aggressive cases that

we have here, we are increasing consumer preferences with the growth in the PEV market. This is reasonable because even our survey shows that those who open PEV or the PEV owners are more likely to be repeat buyer of PEV. In other words, those who currently own PEVs, they are more likely to buy PEVs for their next vehicle. So it is only reasonable to have these assumptions for the reference high and aggressive cases. As the market grows, so does the consumer preferences for these vehicles.

The next category of inputs that we are using, of course, are the government incentives, and these are our policy variables. We have the federal tax credit and you all have heard about the news -- I think it came out this week -- of the federal government's intention to just do away with the federal tax credit. We haven't quite captured that if they stop issuing the tax credits in 2019. However, as you can see here, in the low case, we are somewhat capturing that. We are eliminating it after 2022. So our low case forecast is based on the assumption that tax credits will be eliminated after 2022. In other cases, in all the other cases, we are maintaining our tax credits. Federal tax credit is in place, but as you know, some of the vehicles are going to lose their tax credits, like Tesla and GM, because

they are sold over the threshold, the 200,000 threshold. And therefore, the amount of -- we are making adjustments by reducing the amount of tax credit over the different scenarios that we have.

The next policy table, which is state related, is the state rebate, and we are keeping the state's rebates in place until 2025 for all of the scenarios, but in the aggressive case, we are extending that to 2030 for the PEV and FVE, which are considered pure exempt vehicles. I should also mention that in our model, in our forecast, we are -- when we include state rebate, we provide that to all of the PEVs that are sold in the market, whereas, in reality, if you can imagine there are some income thresholds that have been introduced into a legitimate criteria, but in our forecast, we are granting that to 100 percent of the vehicles that are purchased in the market.

When it comes to the HOV access, we are maintaining the HOV access to 2025 only in the high scenarios, and we are extending it to 2030 only, again, for the pure ZEV vehicles; that is, the PEV and FCV. As it comes to the vehicle attributes, availability of PEVs; that is, the number of makes and models that are available in the market. In the low and the reference scenario, these are available in 14 PEV models and

available in 14 of the 15 CEC LDV classes. So when we are forecasting our light duty vehicle demand, we are forecasting for each class of vehicle. In other words, when we're 15 classes of vehicle, we are forecasting them one by one and by each of the technologies. But in the reference and in the -- in the reference and in the low case, we do have PEV models in 14 of the 15 classes of vehicles versus in the high and the aggressive cases where we are offering 15 PEV classes in, in the model. So we have them available in 15 classes.

Our vehicle prices are essentially determined by battery prices -- not essentially, but they are derived from the battery prices. So it is important for us to know what those battery prices are going to be. The forecast of battery prices are important to price of the vehicles. This -- in different scenarios, we start out with $120 in the low case per kilowatt hour to $100 in reference and $80 in the high case. In the aggressive case, however, we are going as low as $70, which is what Bloomburg is forecasting for the low price forecast of Bloomburg. We also did another adjustment to the vehicle prices this time around because of the tariffs as we mentioned before. Tariffs on aluminum and steel are, obviously, going to increase prices of vehicles, but they are going to be applied to all vehicles not

just PEV, but we apply that to all of the vehicles. We account for that in the low scenario. And so the aluminum and, and steel tariffs are already in place, and we applied that in the low scenario, but we did not apply that in the reference high and aggressive scenario. We all know that there is all these talks about the trade war and not just the aluminum and steel tariffs, but also tariff on, on cars in general and automotive parts. But since it is lawful right now, we didn't really do anything about it. We just assume they don't exist, but we did apply aluminum and steel in the low demand case.

As it comes to the range, we have higher ranges in -- for our PEVs and in this forecast as compared with last forecast consistent with the advances in the technology that we have seen in the market. The numbers that you see here for range, these are sales ranked averages. So we are taking whatever shows as sales in our model, and we are multiplying by ranging different classes are different, and these are the numbers that are pretty good actually. We have pretty good ranges. Here in the high and aggressive case, we are about 280 miles versus reference at 260 and the low in 250 miles.

When it comes to the refueling time, we have generally just considered the fast chargers here, and as

you can see here in the low and reference cases, we have about 15 to 21 minutes, and in the high cases, we have 10 to 16 minutes. Again -- and consider this only on the fast chargers. As it comes to the time to station, our criteria really comparison is to gasoline vehicles. So does it take more time than gasoline to, to, to reach a station to fuel your car with gasoline compared to an EV. And as you can see here, in the reference high and aggressive, we are assuming or we have reaching same amount of time, same number of minutes as you would require to reach a gas station. It is only in the lower case that it is taking seven, to eight, minutes to reach a charging station, but in the reference high and aggressive, it is the same thing as we assume for the gasoline stations, which is about five minutes. Now, given these -- and we are coming up with the 2030 ZEV population ranging from 2.6 million in the low case to 5.47 million in the high case -- I'm sorry -- in the aggressive case.

COMMISSIONER SCOTT: Aniss, before you move on from that slide, one thing that the, the forecasting them and I talked about here with the -- both the refueling time and the time to station, um, just it's important to note that that's to a PV fast charger in most instances, and it's a little bit difficult to

capture, "I plugged in at my house," right, which is no time to station or "I plugged in at my work," which is also no time to station, and that's something that we're thinking about how to dig into to add some additional granularity here, but this is to fast chargers.

MS. BAHREINIAN: Thank you. So this is going to give us the statewide light duty ZEV population forecast. So as you can see here in our high case, we are exceeding the -- focus plan update of 2017. We are at 4.4 mill vehicles, ZEV vehicles. We had about 4.2 million in last IEPR, and now is it important 4.4 million. In the high case at about 5.5 million, we are exceeding the goal that is set in the Governor's executive order for ZEVs. Because some people ask questions, I think it is important to clarify that Governor's executive order, the goal there, the five million, is really ZEV not PEV, and that's important to know, which means that it includes SEVs or hydrogen vehicles as well as plug-in hybrid vehicles.

So finally, coming down to the PEV forecast. We have -- our forecast changes from two and a half million in 2030 for the low case to 5.3 million in the high case, in the aggressive case. So the numbers are actually pretty good. We are exceeding a lot of the expectations, even some that have been set in other

future studies that have been presented in different places. Now, what is important about our forecast, which is different from many other forecasts, except for Bloomburg, is the composition of the plug-in electric vehicles. The composition in our forecast shows a lot higher PEVs than PHEV, which is true in all of our scenarios. In all of our scenarios, we are showing more PEVs than PHEVs and that is the direct result of the survey that we completed in 2017, which showed consumers have higher preferences for PEVs as compared to PHEVs. As you know, the recent announcement by GM that they're going to drop -- is perhaps further support for what we are doing here but it is only our forecast and Bloomburg's forecast that is showing the higher numbers of PEVs in the forecast. And I think -- so as a result of that, we come down to electricity consumption forecast. And I should mention up front that one of the assumptions -- consumption electricity fuel conception in general is the result of fuel economy, number of vehicles on the road, as well as the VMT. I should say that we made the assumption that PEVs have the same number of miles as all the other vehicles. So the assumption in our model is that PEVs have -- drive the same number of miles as all other fuel types. Eventually, that is what has to be, and this is the

longer term forecast. So we have the same number of miles, and we also have lower PHEV lower number over PHEV compared to others. The result is that electricity consumption is also growing almost parallel to our PEV population growth. And it starts with about 2,000 in 2017, and it goes all the way to 18,000 in the high case in 2030. So it is growing faster than the growth in, in total electricity demand, and as a result, the share of the electricity consumption for the PEVs is growing as a share of total electric conception in the state.

Finally, it takes a village to raise a forecast, and as you can see here, there are a large number of people here who are involved in this. We have a great number of team members here, and we are listing all of those. I dropped one of them. I, I overlooked one of them, and that is one of our students who has just recently joined us, and he did a lot of work actually in determining the impact of aluminum and steel on the prices of vehicles. So he did a lot of work on that. His name is Alex Longday, and I'm sorry that I excluded his name from this list.

Any questions?

CHAIR WEISENMILLER: Great. Thanks again.

MS. RAITT: so next is Cary Garcia again.

MR. GARCIA: All right. I'm back. So we're going to get into some of the statewide results. I think that is a better plan than we've previously did. So you get some context of the electric vehicle PV forecast, but before I get into the results, I should have mentioned this earlier, but we have shared with our stakeholders the actual raw results and data, but we're still printing up the forms, the actual forms that we produce. So when you get those out early next week, but if any stakeholders have any questions during the comment period, feel free to contact us, and we can walk you through that and share any additional number or details on the forecast. So I just wanted to throw that out there.

CHAIR WEISENMILLER: I was just going to say also if anyone thinks that our WebEx might help, you know, just let you know.

MR. GARCIA: Sorry about that. Okay. So, kind of, the biggest changes here, as you saw in the economic and demographic projection, is really the commercial sector that saw the biggest declines and that was due to the commercial employment going down quite a bit and some smaller decline in the agriculture sector, but residential, given that one of the biggest drivers is persons per household. So household decline alone in

the population remained about the same, and then you also have some -- a slight decrease in the rates as well. And then in some of the planning areas I'll get to later this afternoon, you'll see that percolating income doesn't necessarily decline into the planning area, which is also another driver for residential sector. So -- and then you'll also see some small changes in the resource extraction, a higher level for GSP, which is a big driver there with the mining sector. So that grows ever so slightly in the planning area, but I guess the biggest take home is that you're really going between residential growth and commercial decline, and so you end up with something very flat. And you'll see here in the -- in the next slide that really consumption and sales are about the same. It's really not a lot of big changes in this case. Probably more changes in the high scenario relative to 2017 but mostly, we're, kind of, along the same path. So before I get into the major actual statewide results, I just want to point out that we do include climate change impacts. And so this is what we -- we haven't made any changes to the projections that we incorporated last year. We're simply adjusting them similar to AME in that we're adjusting them to be incremental to this new starting point. So overall, we have about 1280 gigawatt

hours of climate change impact in the mid case and a little bit more so -- in the high demand case. So low demand -- the low scenario doesn't really include any climate change impacts at all. So these climate impacts are mainly around increases in cooling and heating degrees, and we've developed those based on climate change projections that we've received -- and make those adjustments there. This is a similar climate change impact from the peak side. We see it's a little bit more spread on the high scenario in comparison to the energies, but once again, about 740 megawatts of the peak demand impact by 2030.

So looking at statewide consumption as I mentioned, you know, you have that trade-off between residential consumption, you know, maintaining and if not growing a little bit; while commercial sector, kind of, drops off, and so you end up with something very similar to what we had last time. Actual consumption is a tad bit higher in 2017. At the mid case is just a little bit lower there. You see 0.11 percent, but by and large, the trend is about the same going forward. And if I were to put up -- I mean, obviously, we get -- all the higher scenarios from last time. You see that high scenario as being a little bit higher than last time. Whereas, the low scenario is, I think, a little

bit -- a little bit lower than previous.

So looking at statewide sales, same thing. Really, as Sudhakar mentioned before, there really wasn't a whole lot of change in the PV. There were some minor adjustments, but in the end, it, kind of, all shakes out to being very small change on a statewide level, but once again, just ever so slightly lower in our mid case and compared to 2017. So we're right under maybe 290,000 gigawatt hours or so. So as I mentioned, we didn't make any changes to the Additional Achievable Energy Efficiency, but what we did do was, once again, adjust that incremental to the new starting point. So, so in the mid, mid scenario for 2017 -- or sorry. In the mid scenario for this new update, we're about 35,600 gigawatt hours of electricity. I don't have it here, but the peak demand of reduction is about 11,200 megawatts, but once again, these are basically the same as we've had last year, and we'll update these again in the 2019, but we keep them the same for the update.

In looking at managed sales -- so the managed sales forecast will include the mid case for AAEE as well as the mid case for AAPV. In this case, we're a little bit higher and, as Sudhakar mentioned in the his -- in discussion about AAPV, there was some of that squeezing a little bit so there was a little bit less

AAPV relative to 2017 so that you see that mid case managed sale in that long-term protection. But otherwise, the basic trend is more or less the same given that the consumption is about the same and the sales projection is relatively the same.

That's what I have for this piece. I have another slide to talk about, but if there are any questions from the dais on the economic projections.

CHAIR WEISENMILLER: We're good. Thanks.

MR. GARCIA: All right. I wish there was something more exciting I could show that there was dramatic changes in the economy but I think -- I think what really is happening is folks are unsure about what's going to happen in the future I think, and as Aniss mentioned, you know, there potentially is going to be a downturn, where we have, you know, one percent economic growth by 2020. But I don't think we're quite there yet. Everybody keeps feeling like we're going to get there. So I think, perhaps, in 2019, we might see some of those changes occur, but, you know, with tariffs and all these other things, GM is changing some things. So we might just be right in the middle of where we're going to start seeing some major changes in the future. But right now I think everybody is, kind of, holding, kind of, like, keeping projections about the same.

CHAIR WEISENMILLER: I think so. I think there's been some drop in the state's revenue -- but again, everyone's, sort of, waiting for the other shoes to drop.

MR. GARCIA: Exactly. And then one thing I wanted to mention in the process for this year is that we've revaluated our weatherization process and that was partly due to stakeholders seeing some bouncing year to year into what our estimated projections were for the weather starting point, and so in this, this year, we tested several models to basically see what we could do about alleviating some of that balancing. Presented this analysis to the DAWG and mentioned census on this solution, which is, essentially, we want to make sure we're applying a consistent form and -- to our models over time, and then what we need to do is evaluate those models, sort of, in a rolling window looking at forecast error and particularly around the, the one example is using the top five peaks to make sure we're still -- the model maintains the best performance. And if we need to reevaluate it, we can use this test of error and then bring that to the stakeholders, and then go through this process, either through the DAWG as well as the JASC to make sure we're still on the same, same page.

COMMISSIONER MCCALLISTER: I want to just

highlight the importance of this because we need to make sure that we get the smoother year to year as we need, but we also don't want to lose sight of the reality that we're trying to model, right. So, so -- and as climate change and as we get less predictable weather, we're going to have to try to find the balance. And that's an ongoing process year to year that really does depend on this collaboration across the agencies. So I just want to make sure that that's, sort of -- we're, kind of, as transparent about that as possible so we can both, you know, keep things understandable but also capture the reality out there not just, sort of, end up dependent on these models with specific, you know, with specifications that are difficult to change. So --

MR. GARCIA: Right.

COMMISSIONER MCCALLISTER: You know, so thanks a lot, and I think that, you know, the cross-agency collaboration with these and staff certainly goes on every day is really important to let everybody know what we're doing.

MR. GARCIA: Yeah. And there was some really great, I think, conversations in the JASC and the DAWG meetings as well in particularly around climate. I think that's something I would like to explore next year to see, and I think one of the biggest conversations

was, you know, we -- to give a little background of the process, we use 30 years of weather simulation to develop the weather normalized values, but, you know, folks have supported that. You know, if climate change is occurring, then maybe that 30 years of, sort of, normal, maybe we can, kind of, shrink that down and look at different -- maybe the more near-term weather is actually more of a normal weather scenario.

COMMISSIONER MCCALLISTER: And also, I think the weather is going to be more variable, and the extremes are going to -- potentially going to -- going to mess with your modeling outcomes, right. So we got to figure out how to be consistent --

MR. GARCIA: Right. And then that's going back to the model specifications of form to make sure we can actually model that appropriately. So --

COMMISSIONER MCCALLISTER: Okay. Thanks.

MR. GARCIA: So a few things there but I think we're on a -- on a good path going forward.

I think I'm quite a bit early, which is unusual for our IEPR workshops, but I'm happy to take any additional questions either on this weather normalization or the other pieces of the statewide forecast if folks have any questions.

CHAIR WEISENMILLER: Actually, let me ask

you a question. So --

MR. GARCIA: Yeah.

CHAIR WEISENMILLER: We, collectively, had to adjust August and September forecast, you know, because of the weather normalization issue. How did the actual sales come out on that?

MR. GARCIA: On the sales?

CHAIR WEISENMILLER: It was the peak number, you know, for last August and September. I don't know if you know or if Neil knows. It'd be good just to get that in the record is I guess what I'm saying.

MR. GARCIA: Are you -- I think --

COMMISSIONER MCCALLISTER: 2018 August and September, we were -- before those months actually occurred, we were talking about what --

MR. GARCIA: Oh.

COMMISSIONER MCALLISTER: -- will be and well, what were they?

MR. GARCIA: Oh, yeah. I don't know. Off the top of my head, I do not know what the August -- I want to say --

CHAIR WEISENMILLER: Because we had our original forecast, and then we came up with the plug number since the original seemed really low. But it

would be good to at least have on the record, you know, or on a piece of paper the, sort of, original plug and then what actually happened, you know, go ahead.

MR. GARCIA: So I don't --

MR. FUGATE: I don't have them on the top of my head, but that's something we can perhaps enter in the record perhaps after lunch.

CHAIR WEISENMILLER: Yeah. That would be great.

MR. GARCIA: Okay. I see blank stares and maybe some hungry people.

CHAIR WEISENMILLER: Not to let you off the hook too easily.

MR. GARCIA: Okay. We'll leave it at that.

MS. RAITT: So we're going to take a break. I don't know if you wanted to take a full hour or come back at 1:00?

CHAIR WEISENMILLER: Let's first give people an opportunity for public comment so that it might be that some folks give public comment now and then hit the road. Of course, I -- we, obviously, don't want people to give public comment twice, but, you know, as a convenience, if you have public comments now, that would be great.

Anyone in the room? Anyone on the line?

Why don't we come back at, say, 12:30? Yeah.

(Break taken.)

MS. RAITT: All right. So we'll get started again back on the IEPR workshop on the demand forecast, and so our speaker -- first speaker is Chris Kavalec from the Energy Commission. Our first speaker is Chris Kavalec from the Energy Commission.

MR. KAVALEC: Good afternoon. I am Chris Kavalec from the Energy Assessments Division, and I'm going to talk about our hourly load model and some -- show some results. Um, hourly load model is something that we first put together for the 2017 IEPR forecast, and today, I'm showing what I'm hoping is a new, improved version of that hourly load model. A little bit of background, the reason why we decided to start doing an hourly analysis is that to do a -- anymore to do a peak forecast properly, you have to have an hourly analysis behind it to capture the, um, peak shift originating from some of our demand modifiers, particularly PV. These modifiers can push the peak out into an -- and have started to, in fact, push the peak out into later hours. And so if you don't account for the peak shift, you're going to be understating your

peak forecast.

Also, historically, um, we have developed, um, a short-term forecast for RA purposes that includes monthly peaks. And this is -- had been done, sort of, separately from the IEPR forecast. And it's -- it wasn't adopted with the IEPR forecast. What we're proposing to do now is to use this hourly load model to develop short-term monthly peak forecasts for RA purposes at the TAC level that would then be used as benchmarks for the ensuing RA analysis. And these monthly peaks would be adopted along with the rest of the IEPR forecast, and we've had discussions with CPUC and CAISO staff, and they seem fairly satisfied with the results so far and that the hourly load model can provide a reasonable peak forecast.

MAN IN AUDIENCE: What's RA TAC?

MR. KAVALEC: Oh, I'm sorry. Resource Adequacy and TAC is the Transmission Access Charge area, which means PG&E is a TAC, Edison is a TAC, and San Diego is a TAC. You also have Valley Electric, which is a very small TAC but also part of CAISO.

MAN IN AUDIENCE: Thank you.

MR. KAVALEC: And also a flexibility analysis, this is a potential tool for use in the flexibility analysis that CAISO, slash, CPUC does. We

don't have any agreement among the agencies yet for use of the hourly load model, for, for this -- these analyses but we offer it as a potential tool for use and flexibility analysis.

A little bit about the structure of the model; I won't go into a lot of technical details and a lot of you've seen this already, but basically, what we have is a -- is a regression model that specifies the load ratio, meaning the load in a given hour divided by the average load over all hours in a year as a function of calendar and weather variables. And the weather variables you see listed there include temperatures, hourly temperatures, dew points, and cloud cover.

Now, the reason that we do this -- do it this way, that is, estimate hourly load ratios as opposed to hourly loads is that we can then apply our traditional IEPR annual forecast of consumption, convert that into an average hourly consumption by dividing by eighty-seven sixty and applying those to our estimated load ratios. In that way, we take into account, through the IEPR -- traditional IEPR forecast, the impacts of econ and demo and rates and other effects. So in other words, the IEPR long-term annual forecast is accounting for econ, demo, and these other things, and the hourly load model with its load rate -- estimated load ratios

is accounting for variation within the year due to weather and calendar effects and different hours.

So we, we develop a consumption load using these load ratios applied to annual conception, and then we adjust those to get our final sales forecasts by incorporating EV charging profiles, PV generation profiles, residential TOU impacts, and hourly additional achievable energy efficiency. And PV there includes, as we saw earlier today, both predictive PV coming from our model as well as Additional Achievable PV through the 2019 Title 24 standards.

Now, in our forecast, we typically assume average weather for the length of the forecast period, and that's because, obviously, weather is impossible to forecast more than a few days ahead. So we don't even try. What we do is we provide a forecast that assumes a typical weather year. And this -- the same thing goes for our hourly load model. We want to take our regression results and develop weather normalized load ratios for each hour. To do that, we simulate 18 years of weather history, 2000 through 2017. We run those through our regressions and using -- apply our regression coefficients. And then for each of those 18 years, we change the calendar 17 times. So that way, we start the calendar on a different day of the week, so

that way you realign your calendar effects with the whether variables. So in one year, you might have the maximum temperature on a Thursday, and that's your peak. But then the next simulation, that high temperature may come on a Saturday, and that's no longer the peak.

COMMISSIONER RANDOLPH: Can I ask a quick question?

MR. KAVALEC: Sure.

COMMISSIONER RANDOLPH: The climate change impacts, do you see the same as what was described earlier where you're making assumption about increased heating days and, and cold weather days? Is that -- is that how --

MR. KAVALEC: Yeah, that is incorporated, and I'll get to that in a later slide.

COMMISSIONER SCOTT: I had a question also on the previous slide, where you mentioned the consumption load is load served by utilities plus PV energy minus PV. Is that -- is that backwards? Should it be plus EV load minus PV?

MR. KAVALEC: Okay. So to go from total consumption --

COMMISSIONER SCOTT: Uh-huh.

MR. KAVALEC: -- we add in PV. And then we -- so that's -- so basically, we're taking sales,

adding PV to it. That gives you a measure of the total consumption.

COMMISSIONER SCOTT: Okay.

MR. KAVALEC: The reason that we're subtracting on EV from that is that we model EVs explicitly within the model using changing profiles. That's why we break it out.

COMMISSIONER SCOTT: Okay.

COMMISSIONER MCCALLISTER: So that consumption is non-EV all conception except EV consumption, which is its own -- is that --

MR. KAVALEC: That's right, yeah. But then when you talk about total consumption coming from a model that EV at an hourly level is added back in. So total consumption includes EV ultimately.

COMMISSIONER SCOTT: Okay. Got it.

MR. KAVALEC: Okay. So we do a series of a hundred and twenty-six different simulations for eighty-seven sixty hourly loads, and then we group together the highest hourly loads estimated in the simulations, all a hundred and twenty-six of them. And we take the median of those hundred and twenty-six hourly loads, and that becomes our weather normalized hourly load peak ratio for peak load ratio. Then we group together the second highest loads simulated and

take the median of those hundred and twenty-six. That becomes our second highest load ratio and for the year. And so on down the line all the way down through eighty-seven sixty.

Okay. So now what we have developed is a set of the eighty-seven sixty weather normalized load ratios. Now, the next step is we have to assign those ratios to an actual day and hour, and that's where it gets more complicated. For the 2017 forecast, what we did was to say, "Okay. Let's take what we consider to be average years for each TAC, the three IOUs, in terms of cooling degree days and heating degree days, and use those to assign our weather normalized load ratios." So for example, we used 2012 for PG&E. So if the peak in 2012 for PG&E was on July 25th from 4:00 to 5:00 o'clock, that's where the highest weather normalized load ratio would be assigned. And then the second highest would be on the date and hour, the second highest load in 2012, all the way down the line. Okay.

But that created a couple of issues, so we have addressed in this forecast. Um, first of all, just because a year, as a whole, is average, could be considered average for a given TAC area, that doesn't mean it's average for every month. Um, so what ended up happening is we got some sort of unreasonable peaks, um,

for the TAC areas in some months just because that month within an average year was unusual. Okay. In addition, we ended up -- we use two different years, 2009 for Edison and San Diego and 2012 for PG&E. And this created a misalignment so that when you added up the individual TAC areas, you were not getting a good estimate of the CAISO coincident hourly load because they were coming from two different years. They were misaligned. So we needed to find a new, a better method to do this to avoid these problems. And an intuitive way of doing this we thought was to measure the average loads historically over a number of years by day type. And by day type, that means, for example, the first Tuesday in March or New Year's Day or the second Thursday in June and so on. Okay. So we computed averages for each TAC area for all the different day types for each hour and each month. Now, the advantage of this is that it keeps the CAISO coincidence intact. You're taking an average PG&E load, an average Edison load, an average San Diego load, well, you add those together, you're going to get an average CAISO loads. Okay. So it preserves the coincidence. However, because you're taking averages for each day type and month and hour, you're, kind of -- you're suppressing the variation within a given month. So you're not going

to get a very good measurement of the peak. Okay. So we had to develop a second step that would preserve the real world variation that you see within a given month.

So what we did in our second step was to go through each month and say, "Okay. Here's the average of the highest hourly load over the historical period. Here's the average of the second highest hourly load for this month over the historical period," and all the way down through however many hours there are in a month. Okay. We then assigned these. We substituted these measurements for the average loads in the previous step. So if the highest average load from the previous step in May occurred on the second Tuesday at 4:00 o'clock, well, this computed average of the maximums in May would go to that day and hour. Okay. So we did that for all the months and all the hours. And what resulted then was a set of eighty-seven sixty indicators that we could then rank and use those ranks to assign our simulated weather normalized hourly load ratios to every day and hour.

A little bit about the hourly profiles. Um, consumption hourly profiles, we discussed. It's entered into the model separate from electric vehicles, but ultimately, electric vehicles added back in. We have PV generation profiles that we use coming from E3 analysis

of the California solar initiative data, residential TOU that we develop in house. As Carey mentioned earlier, the same AAEE profiles as we used in the last forecast but adjusted to be incremental to 2018 and climate change. Now, as, as Carey mentioned earlier, for each planning area, we develop an estimate for each year of the impact of climate change on peak demand and on annual energy. Okay. We don't -- or didn't have anything to apply to the hourly load model, and this created an issue for me because we would have stakeholders asking us, "Okay. You have your hourly load model results. Can I just pull out the peak from there?" And we'd have to say, "No, because you have to make an adjustment for climate change and add that back in." And that, that -- that's probably not -- we would like to provide something -- an hourly -- an hourly load model result that incorporate everything so that you can just pull out the peak or whatever monthly peak you want to pull out and you don't have to make any adjustments. So I decided to try to integrate climate change impacts into the hourly load model. So what I did was I started with the peak impacts of climate change and assigned that to the peak day and -- peak day and hour. Then I needed to assign it to different hours, all the rest of the hours in the summer. What I did was to impute the

amount of cooling that's going on in each hour. Um, the way I did that was to take an average load shape in April, where you don't have much cooling or heating and compare that to all the other days and hours with the difference and the summer being the amount of cooling; the difference in the winter being the amount of heating. So it's just a rough estimate of the amount of cooling by -- and heating by hour.

Okay. So we have our peak climate change adjustment. Then we apply a fraction of that heat megawatts to the second highest cooling -- estimated cooling load, whenever that day and hour happens. And then we apply a fraction of that to the third highest cooling load, all the way down the line. And that fraction's calculated so that if you add up all of the hourly impacts, you get the annual energy impact, the increase from cooling.

Okay. So we did that for the hours in the summer months. Um, for heating, it was the same thing going in the opposite direction. Um, we imputed the amount of heating by comparing the winter months' load shapes to April. Then assigned -- oh, taking a step back. When we estimate the impacts of climate change, we have increases that come from more cooling needs from increasing amounts of, um, cooling degree days, but we

also have decreases in the load coming from less heating requirements because their heating degree days are going down. Okay.

Okay. So this decrease in load was then allotted to the different hours in a similar way as the heating increases so that the sum over all the hours in the winter equal the, the estimate of the annual impact from less heating degree days. So this is an, admittedly, kind of, crude way to do it, but as I said, I wanted to integrate this in just so -- to make the hourly load results more complete. Going forward for the 2019 forecast, we're -- we've been talking to Scripts Institute and they're optimistic that they can produce a set of hourly impacts of climate change. So for the next forecast, we won't have to use such a crude allotment to the different hours.

Um, a couple other adjustments we had to make. We agreed with -- to make some adjustment for some of the small -- a couple of the smallest LSUs. One was Vernon, who has a big industrial customer moving in, in 2021. And the other was Silicon Valley power, which has some big data centers moving in, which will have significant impact of -- on their load. So the same thing here. We have an annual peak estimate and annual energy estimate from these big industrial and commercial

customers moving in, but rather than make, you know, an adjustment to the hourly load model results after the fact, I allotted these impacts to each hour. Okay. So for example, Vernon we have a peak amount, and we have an annual energy amount. So I assigned the peak amount to the peak hour and a fraction of that to the day with the next highest load all the way down. And that fraction calculated so that the individual hourly impacts add up to the annual energy impact. And that was -- those loads are fairly flat. So there was -- that fraction was pretty close to one because these are big -- this is a big industrial customer and a big commercial customer.

Okay. So all that goes into the, um, hourly load model. So to be complete here, what consumption really is the initial estimate of consumption. Then you're adding in EVs. Then you're adding in climate change impacts, and then you're adding in these two adjustments that I just mentioned. Okay. That's our -- that's our actual, final consumption in the hourly load model.

COMMISSIONER MCCALLISTER: Just to be clear, Chris, you, you start -- you weather normalized before all that? You're doing weather normalization and then that's -- the weather is what you then make all these adjustments to?

MR. KAVALEC: That's right.

COMMISSIONER MCCALLISTER: And then also, are you concerned about April not being, sort of, neutral enough? I mean, it's probably the most neutral month, but is there an issue with having some middle cooling or heating in there that, sort of, messes you up?

MR. KAVALEC: Yeah. In fact, there's some days you can have both cooling and heating, where it's cool in the morning but it's warm in the afternoon. And that's -- so there are obviously more refined ways of doing this, I'll admit.

Okay. So now we have our hourly load model and some results and we want to test these results. So what I did was to test, compare the 2018 results coming from the hourly load models with recent history and with our own weather normalized peaks for 2018. So first, here, are whether normalized annual peaks using our traditional process for each of the IOUs, and these are numbers that we as, as usual develop using an econometric analysis and simulations. And then we confer with the IOU just to see what numbers they have, and we sometimes settle or, or make slight changes based on their results. But anyway, these are the three weather normalized peaks that we ended up with for the

IOUs in 2018 in the middle of the column there.

To get a CAISO system, um, coincident peak, what we do typically is we will add up the weather normalized peaks for each of the TAC areas then add in VEA, which isn't shown here, and apply a coincidence factor, which in recent years, has been .9 .965 and apply that to that sum. That gives us the 46,321 PVC here.

In comparison, coming out of the hourly load model, we see that the weather normalized peak is pretty close for PG&E, a couple hundred megawatts away; a little bit farther away for Edison TAC area, and a little bit high for the S PG&E TAC area. It should be kept in mind here that the output coming from the hourly load model is coming from a forecast. It's coming from a forecast for consumption, and it's coming from a forecast for PV. Whereas, the annual weather normalized peaks in the middle column come from using actual loads in 2018. So we think those are a better estimate. And also, we're projecting in 2018 reductions in consumptions for PG&E and Edison, which is driving down this number relative to the middle column and an increase for San Diego. Okay. And again, that's a forecast, which is pushing at the San Diego number.

But anyway, what we will do -- we haven't done this yet because we just agreed on Tuesday afternoon

with the IOUs on the weather normalized peaks, so I haven't had time yet. But we will calibrate the hourly load model results for these 2018 weather normalized peaks shown in the middle column. Unlike in our traditional process, you don't need to develop a coincidence factor because all you're doing is adding up the individual TAC areas, the three IOUs through EEA for each hour and selecting the max number, and that's your CAISO coincident system peak. Okay. And if -- and in doing that, the affective coincidence factor that you get comparing the -- some of the IOU and VEA peaks with the CAISO system peak coming from the hourly load model is .949, a little bit lower than what we have been using but still within the reasonable range.

Now, in looking at monthly peaks recently, there's been a lot of attention paid to that in the RA world, and folks have typically been looking at the last five historical years and comparing that to the RA forecast and using that as, sort of, a benchmark or a standard for which to judge the RA forecast, monthly fee forecast. But this, this is not the greatest method to use because using averages for only a few historical years, you have a lot of -- you can have a lot of volatility as you change the number of years or you update your five-year total. So I give some examples

here. So the -- using June and the EMS data that we get from CAISO, the average peak from 2013 to 2017, that five-year period, is around 43,500 for June. Now, let's say you decide to add a couple more years on and look at the average peak from 2011 to 2017, well, you see, you go down by 1500 megawatts for your average, or let's say you want to weigh more recent years to get a better indication of more recent developments, 2015 through 2017, well, then you're up, you know, 400 megawatts higher than you were using your original five-year period. And then if you update your five-year period and use 2014 to 2018 instead of 2013 to 2017, you wind up 1500 megawatts lower.

And then below that, I show the average for the entire period for which we have EMS data, 2006 through 2017. So because of this volatility and these comparisons I'm making between the hourly load model output and the monthly peaks, I'm going to use the whole period 2006 to 2017. There's no perfect historical period for, for comparison, and we know there's been a lot of changes in the electricity market since 2006, but you're capturing a lot more weather years, and ultimately, weather is the most significant -- still the most significant driver of variation within a year. So you want to capture as many weather years as

you can, and that's what we have.

So this graph compares what was predicted in the hourly load model for 2018 for monthly peaks in dark blue versus what the average is over the 2006 to 2017 period. And you can see they're pretty close, but you really don't want to compare with the magnitude, the absolute magnitudes of loads, because loads are changing and overall, you have growth. You know, sometimes, you have decline; sometimes, sharp increases, but overall, the trend is increase. So what you really want to look at is the ratio of the monthly peak to the annual peak, and that's what I have here, and you can see we're even closer. Okay. So it seems relative to history, it seems to give a pretty good -- pretty good estimates of monthly peaks at the CAISO level. You also want to look at monthly peak coincidence, what the coincidence is within a given month. So in this case, you're summing up the TAC area peaks within a given month and comparing that to the CAISO coincidence peak, and you can see the coincidence factors there are all between .97 and 1, which is consistent with the historical data. So I think we've solved our coincidence issue for our hourly load model because these numbers look pretty reasonable. Then we want to look at individual TAC areas, and what's important in the RA world is not so much the TAC area

absolute peaks, but the coincident TAC peaks, coincidental with CAISO peaks. We're worried about that. So you can see we're comparing monthly rates, the ratio of monthly to annual peaks for coincident peaks for PG&E, and you can see these are pretty close. Not quite as close as for CAISO as a whole. For Edison, not quite as close. We seem to be under-predicting the ratios for most of the months, and for San Diego, we're over-predicting the ratios for most of the months. Now, this could be a defect in the hourly load model, but what I think is going on here is that in the case of Edison, we have seen their annual peaks ballooning in recent years compared to the rest of the year. So that's what -- and when we did our regressions to estimate the model at the suggestion of some stakeholders, we gave more weight to the last three years of the data so we can catch more recent trends and we did that by using a dummy variable for the last three years. So this dummy variable is, is capturing what's been going on recently, which is the ballooning of annual peaks for, for Edison relative to the rest of the year, so I think that's why you see this relationship that I'm showing here.

San Diego, we have the opposite. The annual peaks have been dropping relative to load and the rest

of the year for whatever reason, more PV. So that's why you see this relationship. Okay. And again, as I said, there's no hourly or historical period that's perfect for comparison but anyway.

Okay. Now, back to our regularly scheduled IEPR forecast. What I'm going to show now is the peak forecasts for the IOUs generated with the hourly load model.

CHAIR WEISENMILLER: One second, Chris. Do you know any theories on what's causing the Edison ballooning?

MR. KAVALEC: I think it's because of movement toward the Inland Empire and a shrinking industrial base, which means the remaining load is peak year.

COMMISSIONER MCCALLISTER: Chris, I also wanted to -- I'm not -- I don't quite have this thought fully formed, so I apologize if it doesn't make sense. So -- but are you -- so each of the, you know, the, the LSE areas, the three big IOUs, in terms of the aspect of translating, you know, getting that final peak number and going through that methodology, are there places where the specifications that -- of the model that you used to do that allocation are different? Like, um, you know, is it warranted to have, you know, given the

different context and say even Edison as you just pointed out, does that mean that you need to, kind of, tailor your methodology and decide on a slightly tweaked methodology for each of those to make it fit better, or you really just want to have one methodology that you're using across the board?

MR. KAVALEC: Well, in this particular case, as I mentioned, we, we included a dummy for the last three years.

COMMISSIONER MCCALLISTER: Yeah. That captures a lot of the --

MR. KAVALEC: Yeah, and it's only kept in if it's significant. So if it's actually capturing something, like it is in the case of Edison, it's kept in the model. If not, then it's not used.

COMMISSIONER MCCALLISTER: Okay. So to the Chair's question, you know, some of these influences that may be contextual to each territory would, sort of, be in the dummy variable if they exist.

MR. KAVALEC: Yeah, and that goes for the other variables. So we only keep the variables that are significant -- which are different -- which differ in the different categories.

COMMISSIONER MCALLISTER: Okay. Gotcha. Thanks.

MR. KAVALEC: Okay. So here's our PG&E peak forecast from the hourly load model, which incorporates the peak shift, and starting from the top, the dark blue, we have our consumption peak, which is growing at a healthy rate and similar to PG&E's consumption, which Carey will talk about a little bit later. We then subtract off our PV, and again, the consumption includes all those items that I mentioned, consumption, plus EVs plus climate change, plus the adjustments for Vernon and Silicon Valley. Then you subtract off PV, and you get to the red line and that would be our baseline peak forecast. Then from that, you subtract AAEE and AAPV for two different scenarios -- what we call the mid-mid and the mid low -- to give us our two planning forecasts for PG&E. Those are shown in green and in purple. So those are the two planning forecasts that we adopt and provide for usage by various parties for resource planning. Okay. These are the two scenarios that the Energy Commission recommends be used in the resource plan.

We have two of them because at the request of some stakeholders, they wanted a more conservative version for localized plan. So we have our mid- mid -planning forecast for system wide resource planning, and then our mid-low case for more localized planning. And

they are really close together, which makes me think that maybe in the next round, we should try and put some distance between the two that -- the two different scenarios because they are very close together. So --

COMMISSIONER MCCALLISTER: If you were to -- so the table on the coincidence for the -- and you're doing it for the whole ISO territory in slide 15, if you did that by TAC or by -- if you got more localized with that or more regional with that --

MR. KAVALEC: Uh-huh.

COMMISSIONER MCCALLISTER: -- how much would those numbers go down, you know the fit, if the coincidence --

or how much would they vary I guess?

MR. KAVALEC: I guess it depends on how you disaggregated your modeling because I mean, the, the -- you have -- like, for Edison, you have a wide variety of climates, you know, and, and density of population but overall -- so, so because you have widely varying areas, your coincidence then is going to go down.

COMMISSIONER MCCALLISTER: Yeah, maybe it's worth having a discussion at some point about how low of a number for that coincidence would be, kind of, acceptable, like, trying to figure out how local we want to go with these forecasts, you know. Certainly, you know, I'm interested in understanding demands of impacts

and, sort of, figuring out how to quantify local phenomena.So it would be, kind of, an interesting conversation to have about how nervous we get the lower those numbers go. You know, the less coincidence there is, the more local we get and so where would we draw the line on how much we Want to push for a local forecast --

MR. KAVALEC: Right.

COMMISSIONER MCCALLISTER: -- over time. That's what I wanted, the conversation. I think it might be nice to have a little interaction on that.

MR. KAVALEC: Well, ideally -- well, we do -- we have six forecast zones within PG&E, but we don't yet have the data to support the repeat forecasts.

COMMISSIONER MCCALLISTER: Right.

MR. KAVALEC: And especially estimate the peak shift at the forecast level.

COMMISSIONER MCCALLISTER: Right.

MR. KAVALEC: But these, these territories so big that, you know, ultimately, you want to disaggregate your forecast down further because the behavior is going to be very different in the inland areas versus San Jose or San Francisco.

COMMISSIONER MCCALLISTER: Yeah, as we're talking about what investments we're going to make, you know, lower and lower voltage, you know, what -- it'd be

nice to have numbers to base that on and predict.

MR. KAVALEC: Well, data is coming, hopefully, to support this effort. So --

MR. MILLAR: I was going to say it's -- so yeah, one of the other things we have been looking at -- is supplementing some of this area analysis with our own information about actual consumption in certain areas especially for closer in studies to get a better feel for, for -- within some of those areas don't conform to the overall average for that -- so I think that is a good conversation to keep going as to how far it gets handled through the, you know, complete process here versus a one-off when we have an understanding that is under consideration for reinforcement.

COMMISSIONER MCCALLISTER: Yeah, that sounds great.

MR. KAVALEC: Okay. So on to Edison and peak forecast; same story. Start off with consumption. Adjust by the amount of PV, and then adjust by your AA variables to get our two managed peak forecasts, it's mid-low and the mid-mid. Again, flat little bit lower growth than, PG&E and then San Diego on the other hand, a little bit higher growth when you get down to the managed peak forecasts. And this is coming from, as we will see, kind of, a hefty peak shift in relative

terms for San Diego. So this last slide here I'm showing what the peak shifts impacts are for each of the IOUs. And put another way, this is showing how much you would be understating your peak forecast if you didn't account for the peak shift, and you can see it's pretty significant for -- if you're underestimating your peak forecast for PG&E by the end of the forecast period by 3500 megawatts if you didn't account for the peak shift for the peak occurring at a later hour. And these numbers are, are similar to what we had last time. PG&E's peak shift by 2030 is a little bit -- is a little bit lower. Edison's is, is about the same, and San Diego's is pretty high relative to its size and they have a lot of -- they have a lot of PV in relative terms compared to the IOUs. And we ran into this situation last time where the -- you can see how, how, how different the peak shift is comparing PG&E Edison with two utilities about the same size. And this happened similarly, last time, and, and Edison was concerned about how small their peak shift was compared to PG&E. Well, we have reconstituted the model. We've attempted to account, put more weight in the last three years as Edison suggested. And we're still getting the same results, a much lower peak shift compared to the, the PG&E. And this is happening I think for, for two

reasons; much lower PV relative to, to PG&E and also because the load shape is different than peak days. PG&E's loads tend to remain high later into the afternoon. While Edison's drop off faster as you approach late afternoon and evening. So if your loads are dropping off faster, later in the afternoon, where your new peak may be occurring, you're not going to have as much of a peak shift. And I know Edison will, will remain concerned about this, and as we mentioned earlier, we will put out all kinds of numbers next week and including the hourly load model results, and I will be happy to sit down with Edison staff and go through this and show exactly why this is happening in more detail. And you can, kind of, see from, from this graph when these shifts are happening. By the end of the forecast period, the, the peak period for all three IOUs is seven to eight in the evening compared to currently, around 4:00 to 5:00 or sometimes, 5:00 to 6:00. And so you can see, like, 2027 for PG&E where the slow changes increases. Well, you're having a peak shift to a later hour happening in that year. Edison in 2027, that's obvious. You're having a peak shift to a later hour happening there.

Now, comparing the peak forecast versus what we had in 2017 for the two planning forecast, the mid-mid

and the mid low, you can see that PG&E's is a little bit lower for both of those cases due to slightly lower sales that are driving this. For Edison, negative growth but not quite as negative and that's because overall, they have a little bit less self-generation. So their peak isn't driven down as much. And San Diego, with its big peak shift, a few hundred megawatts higher than it was in 2017, has higher growth compared to 2017, and that's all I have.

COMMISSIONER RANDOLPH: Can I just ask a process question? So you've had an opportunity to talk to our staff and CAISO staff and the IOUs and you're going to be taking comments as part of this process for this workshop. Is there any other stakeholder input that you're taking on this?

MR. KAVALEC: Well, the -- so we have the formal comment period, and then we have the informal discussions that I'm sure will happen. And again, we apologize. We -- by this time, we usually have all kinds of results posted that people can look at. We don't have that yet. So informal discussions with, with IOUs and the agencies, along with formal comment period. Anything else I should add in terms of process?

CHAIR WEISENMILLER: Certainly, we welcome comments from any and every one. You know, this

is, sort of, complicated enough or dense enough that probably the IOUs and POC staff, CAISO staff are probably the ones who are really going to dig into it, but, you know, there will be changes as you know, a lot of people very concerned about your RA numbers.

COMMISSIONER RANDOLPH: Uh-huh.

CHAIR WEISENMILLER: And certainly, point them in this direction or at least they're certainly welcome and, you know, again, I'm sure Chris and the rest of staff will be happy to meet, and we'll post the information. As we say, we might do a webinar or something if people really wanted to dive into some of the nuts and bolts or informal meetings, but we certainly aren’t going to preclude anyone else in the RA process from, you know, contacting Chris or staff, talking about stuff.

COMMISSIONER RANDOLPH: Okay. Great. And remind me what your timeline is for posting.

MR. KAVALEC: So --

COMMISSIONER RANDOLPH: Have you figured it out yet or are you still --

MR. KAVALEC: Well, the results, will hopefully be posted next week.

COMMISSIONER RANDOLPH: Okay.

MR. KAVALEC: -- ones earlier in the week

other ones, later in the week.

COMMISSIONER RANDOLPH: Excellent. Thank you.

COMMISSIONER MCCALLISTER: Well, right now the comment period is until December 20th. Right? I guess so, but if, you know, that -- that's adjustable if it really had to be. Just, you know, if we don't get things out there on time.

CHAIR WEISENMILLER: No. We can certainly talk about something which is two weeks after things posted or something like that if people felt they needed it, right? Staff to either concur or not but ultimately, I'm sure Heather's trying to get the whole thing together at some stage. So this is a part of that process, but again, I think we understand that this is complicated. We want to make sure people have enough time to dig into it. So if there are issues, we can --

COMMISSIONER RANDOLPH: Yeah, excellent.

CHAIR WEISENMILLER: -- later.

COMMISSIONER RANDOLPH: Exactly. All right. Well, thank you.

MR. KAVALEC: So we have a lot of material coming out and the forecast update and coming out in a short period of time, and I realize it takes a while to digest everything, and I know that Terry and Nick will

be happy to work over Christmas if they have to.

CHAIR WEISENMILLER: Continuing the tradition. We should also make sure that certainly Commissioner Randolph and Neil, you know, give us an email saying, "it's now posted."

COMMISSIONER RANDOLPH: That would be great.

MR. MILLAR: Yeah.

MS. RAITT: And Cary Garcia is back to talk about the utility results.

MR. GARCIA: All right. I am back. Hopefully, this is the last time you will hear from me.

Okay. So -- mentioned the actual monthly peak values for 2018, so I wanted to invite ISO staff to put that on the record as you suggested

MS. HOU: Hi, my name is Delphine from the California ISO. Chair Weisenmiller, Commissioners, and Neil. So to report, I wanted to provide a minimum of three numbers that we have for August, September, and October. So the peaks this year that we have on hand at this moment from -- extracted from our system but not yet posted is 45,196 for August; 38,752 for September; and 34,888 for October. So this is what I have currently extracted from the system. Do you have any other questions?

CHAIR WEISENMILLER: Yeah. Now, how

does -- it would be good to get that in context of, sort of, what the original forecast was and then what we adjusted it to out of certain degree of conservatism.

MS. HOU: Sure. What I understand from the presentation that we, at the CAISO, made back in August, actually in July was we did not actually take any action for August but just as a point of comparison, the original forecast for August was 44,923. So again, as compared to an actual peak of 45,196, and then that original 44,900 number was adjusted to, according to the WECC forecast to 45,690. So we were, sort of, right in the middle there.

CHAIR WEISENMILLER: Okay.

MS. HOU: For September, it was a bit different. So the reason why we did actually make a significant capacity procurement mechanism backstop for September was because earlier in the year, we had been expecting fairly high temperatures as well as a decrease in hydro capability and other system issues. And so the original forecast for September was 42,579 versus an adjusted based on the WECC forecast of 43,825. So we eventually ended up having a very low September demand month.

COMMISSIONER RANDOLPH: So your actual was, you said, 38,752?

MS. HOU: Correct. Okay.

COMMISSIONER RANDOLPH: So that was lower than the original?

MS. HOU: Correct.

CHAIR WEISENMILLER: Right.

MS. HOU: So the original forecast was 33,175 megawatts. The adjusted based on the WECC was 7,612. So the actual October numbers were, again, right in the middle, 34,888 megawatts. And again, we also procured backstop for October not necessarily for pure concern out of the peak but mostly because that is the outage season for resources. So we wanted to ensure that we didn't have more resources going on outage than what we could have on the system to meet a peak.

CHAIR WEISENMILLER: Thanks.

MS. HOU: Thank you.

MR. GARCIA: All right. Back to -- back to me.

Okay. So we're going to get into the planning area results. Chris already covered the peak for the IOUs, so I won't rehash that here, but I will go into peak for LA DWP and SMUD, and then after that, I would like to invite the utilities to come up and provide comment at the end, and then we can answer any additional questions after that. So getting into the

PG&E planning area to start off with here in northern California, we have per capita income, which stays about the same in comparison to 2017. And if you recall, the previous projections I had mentioned, income, I believe, goes down a little bit, but it, kind of, changes depending on the planning area that you're looking at. Households here goes down. That will be a driver for persons per household, which will drive residential sector consumption and manufacturing outputs down a little bit and commercial employment goes down quite a bit, so you'll see decline there. But overall, the baseline consumption continues to grow ever so slightly. While looking at the sales growth, you see that decline that about 0.76 percent leading to a continued climb in the managed sales growth which I'll talk about little bit later. So looking at the consumption, we see the breakout by sector here. So residential consumption, as I mentioned, continues to go up, being -- which is driving overall total consumption which is, like I mentioned, slightly higher but still at 1.35 percent. Per capita income, as I mentioned, remains pretty strong here, and then that increasing persons per household is really what's driving that residential sector, but that reduction in commercial employment brings down the 2018 commercial sector forecast relative to 2017, and then you see

the same thing in the industrial sector, which is going to be driven by a lower GSP growth, um, and then agriculture sector goes up a little bit, and that's primarily due to the rates going down in the ag sector.

So looking at managed sales, I just want to remind everybody what the managed sales is. So that's taking the sales forecast, which includes -- well, you basically start off with consumption as Chris mentioned, and we subtract off the PV, and that gives us our sales, and then what I'm doing here is I'm also adding in the mid case AAEE as well as mid case AAPV and subtracting those off as well. So that ends up -- it looks like my graph got cut off a little bit but that orange line there is the new 2018 baseline forecast for the mid case with the inclusion of the AAEE and AAPV. You'll see it higher just a little bit, and that's primarily due to an adjustment he made for DWR loads. There's an overlap between Edison and PG&E and Kern County. So we made an adjustment to correct for the appropriate sales going to DWR there. So you'll see it just level up a little bit, but by and large, we're seeing a decrease in growth of 23 percent annually for PG&E's planning area. And then also keep in mind this -- PG&E's planning area includes more than just the PG&E service territory. There's a bunch of POUs in there. There's also going to be that

adjustment for Silicon Valley power that we talked about earlier in that, but once we publish those forms, we'll have a breakout where PG&E -- the customer as well as the CCA and the other POUs that are included in that forecast area.

Moving on to Edison's planning area, we see per capita income decline here. Household also declines once again, kind of, driving that person per household up, which is the main driver for the residential sector consumption. Manufacturing output, once again, is going down in that commercial sector employment is also going down. So we're seeing this trade off, as I mentioned earlier, really, you're seeing residential consumption continue to grow, but the commercial sector is, kind of, taking a hit. Per capita income is declining but it's not really -- it doesn't have much of effect as residential sector in comparison to that person's per household measurement. So overall, baseline consumption is really pretty close to the same as 1.3 percent annually for Edison, and then we'll see the sales remain close to same as well in comparison to the 2017 forecast. As I mentioned, increasing persons per household, really driving that residential sector consumption, whereas that commercial sector -- take the debt but more industrial and then ag is up just a tiny

bit. But once again, growth really warrants the same at 1.3 percent as far as consumption is concerned. So here again, for Edison, we're looking at the managed sales, which includes the AAEE as well as AAPV. Because we made an adjustment to DWR for PG&E, we have to make the inverse adjustment for Edison. So you'll see that drop down a little bit looking at that orange line for the new baseline forecast. But once again, really not a lot of changes in PV as Sudhakar mentioned earlier today. And no -- so therefore, there's not really much of a change in the AAPV. So really, we're just growing steadily or declining here in terms of managed sales, fraction of percent lower over time.

And zooming on through, so we're getting to the San Diego planning area. San Diego's the exception. They're just their own planning area. There's no other POUs in that particular area. Although, there's the new CPAs that will be coming on soon. But once again, per capita income here actually increases slightly, whereas households, once again, is going down. Manufacturing is doing down in addition to commercial employment. So we see that baseline consumption here increase slightly once again that, that tradeoff between the residential sector increasing, but in this case, it's pretty matched well by the commercial sector decline. So you end up

with a pretty -- consumption ends up being nearly identical in this case. Baseline sales, there's -- as Sudhakar mentioned earlier, there's some changes, PV forecast for San Diego is a little bit higher, so you see that decline there in comparison. But let's -- getting back to consumption here as I mentioned, 1.5 percent nearly matches 2017 forecasts. And then you can see that commercial sector takes quite a bit -- takes, takes quite a hit but then that residential sector is mentioning it and a little bit of growth in, in ag while industrial declines. But in the end, looking at the managed sales, as I mentioned, largely increased, driven by the increased PV adoption there, so you see it's slightly lower. But overall, the growth is decreasing by .25 percent in comparison to 2017. So just a -- remind folks that, that blue line up there is the baseline forecast, and as we apply the AAEE and the AAPV, that brings us down to what the managed forecast would be.

Jumping to LA DWP. Once again, we have per capita income, our household, manufacturing, and commercial. That commercial sector, once again, declining, whereas, households remain about the same here, but in the end, LA DWP, person per household is actually little bit higher than last time. So that's

going to drive that, um, that baseline consumption up a little bit. So in terms of baseline energy sales, um, the growth is nearly the same as, as commercial sales decline, but once again, the residential sector, kind of, picks up the slack, and baseline peak, we have a slight growth, and that's because in the peak econometric forecast, we use residential consumption as a key driver. So if residential consumption is going up, our peak's going to go up. It's less driven by commercial sector usage.

So baseline sales, growth, as I said, slightly slower in here, but you can see they're pretty smack dab on top of each other. Really not a change, too much of a change in PV but less decline in persons per household relative to 2017 keeps that residential consumption up. So there's really not too much of a decline. I mean, visually, you can, kind of, see that here. Looking at the managed peak, this grows slightly higher in 2017. As I mentioned, that's residential consumption really driving that. But you'll see, we came down -- there's a little bit less PV in this in comparison to previously. So if you were to adjust that scale up, keep in mind that we're using a different starting point here, we would be still just a little bit higher in comparison to 2017 forecast.

And last, but not least, we'll move on to SMUD. Per capita income here, as you see, takes a pretty big hit, while households remain the same. Manufacturing output goes down as well as commercial employment. So this ends up being sales growth -- sales growth ends up being reduced by about two point -- .21 percent annually here. And then the baseline growth at the end of the day decreases slightly but remains pretty flat. So a higher starting point as I mentioned but slower growth at 1.24 percent and that's the -- that decrease in commercial sector consumption and sales. Really not seeing that big increase in residential sales. And so we end up just above -- based on the new starting point, just above what we had for 2017, but otherwise, that growth is a little bit slower over time. And there's some additional PV coming on line as well that's making that -- causing that slower growth. Looking at managed peak, this is similar to -- I should have mentioned this with -- we also put AE for POU as well and so we do a projection for SMUD as well as LA that I showed before. So we're including this here.Baseline growth is, you can obviously see, it's pretty -- its going up a little but as you include the AAEE or AAPV, the sales end up being -- or sorry. The managed peak ends up being pretty, pretty flat, but there is some decline in

residential consumption but very little in comparison to 2017. So you end up with that there.

That's about it, but I would -- glad to take any questions on these --

CHAIR WEISENMILLER: Yeah. So --

MR. GARCIA: -- before I move on.

CHAIR WEISENMILLER: So the first one was just to refresh people -- you know, as we're adopting, Silicon Valley Power came in and said because the data centers, you know, we were underestimating the forecast and they were deriving informing this time. I just wanted to see how smoothly those discussions went. Obviously, they, like anyone else, had the opportunity to come in once they see the results and take issue with them, but, you know, in terms of the data you need, you got from them?

MR. GARCIA: Yeah. The data, we have that data. That was pretty easy to incorporate into the forecast. That's a minor adjustment that we have to make, and we did something similar for City of Vernon, but it looks like Chris is going to comment on that.

CHAIR WEISENMILLER: Yes, please. Chris, go ahead.

MR. KAVALEC: Yeah, we had a couple meetings with Silicon Valley, and they provided a forecast, and

it looked pretty reasonable given the claims that they were making, and so what we did was to take their forecast for data center energy and peak usage and adjust it downwards slightly to account for, for the fact that we're able -- we're already going to have some growth in that sector in that building type. So -- but basically, it's, it's very close to what they provided us.

CHAIR WEISENMILLER: Okay. I guess the other thing I was going to at least frame up and, and encourage, another component ultimately on the PC side is the CCA part. You know, and that's something where the last time around, we were struggling to catch up with the growth there or expected growth. And so again, process-wise just trying to figure out how we can communicate best on the CCA part.

MR. GARCIA: Yeah, definitely. I think we've talked about this, the adoption of the, the recent IEPR forms for 2019. We really wanted to dig into the CCA's a little bit more, and I've even thrown out the suggestion I think to a few people here that having a workshop, I think, for the 2019 to dig into that and how we're going to do those projections because it's really going to change, you know, 85 percent of mode is going to be served by CCAs by still, still 2020 is the

projection, if not, sooner. That's going to be a dramatic change I think in the comparison to how we're doing things before, or maybe not. It just depends. I think we need to discuss it and see what changes we need to make to the forecast to look out for that.

CHAIR WEISENMILLER: Right. I think the other thing we were finding in some of the PG and -- PC on box is that a lot of the CCAs would come out originally saying, "This is the plan," to do X, and then when you push them, "Well, what are you actually going to do next year or the following year?" It was a fraction that you could anticipate. So again, that's something that, I think, the two agencies need to work through, how best to handle that.

COMMISSIONER RANDOLPH: Yeah. I think it's going to present some interesting data challenges, too, because you have -- you have the changing business plans, but then you also have increased disaggregation in terms of their different programs, their PV programs, for instance, or their, um, or their rates. And, you know, you guys are going to have to collect this, kind of, the more disparate data and, and figure out how to incorporate it. I wish I had helpful suggestions.

CHAIR WEISENMILLER: Yeah.

COMMISSIONER RANDOLPH: Workshops are

probably good.

CHAIR WEISENMILLER: Workshops are good. Yeah, and I mean, certainly, again, we just need to make sure our staff and your staff are talking. You know, you're right. I mean, once you get into -- you know, because they're struggling to include the account of use rates in the forecast and the question was, "Well, what are the rate structures?"

COMMISSIONER RANDOLPH: Right.

CHAIR WEISENMILLER: And the CCAs and how they differ across the other CCRAs.

MR. GARCIA: Yeah. One minor thing that folks, maybe some folks aren't aware of, just thinking about the rates and how we get them. With a lot of cases, the utilities post those rates, but it's a minor issue because many times, it's posted in a .pdf format. So we don't really have, like, a nice database of rates to go to. And so I think there's a lot of staff, particularly, some of the PV forecasters that are going into these .pdf, you know, file by file, pulling out the rate information. I think even our, our POU rate forecaster as well has done that. So it would be pretty awesome I think if we had a nice database somewhere. Maybe -- I don't know -- maybe I'm volunteering myself to develop some database of this.

COMMISSIONER MCCALLISTER: Actually --

CHAIR WEISENMILLER: I would -- I would note, Pat would point out -- and Pat is a class A market oriented, you know, regulator from Texas saying one of the things they did in Texas was for any, you know, SP in Texas, they have databases, all the rate information. So that, you know, if you're in Houston trying to figure out which of these are you going to sign up with, you go to the database and see what the rates look like for residential, and he was in shock. There was nothing comparable to that in California.

COMMISSIONER RANDOLPH: That does seem like it should be a solvable problem.

COMMISSIONER MCCALLISTER: So -- yeah. There's a lot of history with this discussion actually. There was a strong recommendation action plan. There's been, you know, for whatever reason, there's a lot of resistance, you know, because maybe utilities doesn't need the regulators to do this, and there are templates for, you know, capturing the different elements of virtually any rate structure. And so rather than post them on -- as a .pdf, you know, and make somebody go shape it, like Cary is talking about, you know, it's already public information. So just make it accessible to people, and now that everything's getting automated

on the web, you have a lot of third parties, and there's a lot of people doing analysis that need access to rates, and they get updated every month. They get -- make adjustments, you know, the seasonal changes. And so as soon as the utility has them and approved by the POU oversight board, they, they could just be posted in a machine readable format that would just go into the ether and just permeate immediately throughout, you know, the whole ecosystem of analysis including ours.

COMMISSIONER RANDOLPH: Well, now you're going to have a lot more sources for that data. So you have to figure out, you know, how you're going to -- who's, who's going to be the home and, you know.

COMMISSIONER MCCALLISTER: Well, yeah. DOE actually, you know, has had, you know, long-term effort, sort of, to develop the template structure for that.

COMMISSIONER RANDOLPH: Okay.

COMMISSIONER MCCALLISTER: And so we're -- you know, that, that -- when we first recommended this, it's been four years since we put this into the residential building action plan, but yeah, I mean, who's counting, right, but since then, there's been a fair amount of development on, you know, tools to actually do it. And so I think, you know, there's no reason why we -- there's not much reason why we would

want to necessarily -- I think we should -- you know, resources to get this stuff on line, you know, relatively, expeditiously.

MR. FUGATE: I just wanted to make one remark. I want it to be clear we are, are going to be doing an update of the LSE breakout that we typically do for this -- for this forecast update, too. So I wanted to make it clear that that would be available next week where, sort of, in this process right now of, you know, completing all the forms, what we talked about today is, sort of, the high level, but then we're looking at what data is available in terms of, you know, for these new CA that have gone online just within this last year. What load we expect them to be serving so we can do that breakout for the new CCA.

CHAIR WEISENMILLER: Commissioner, is there someone that the PCA should be talking to specifically?

COMMISSIONER RANDOLPH: I would -- I don't -- I don't know specifically who it would be. So I would just reach out to Simon Baker and just, you know, talk about -- talk to him about who the logical group would be.

MR. FUGATE: We'll do exactly that. Thank you.

COMMISSIONER MCCALLISTER: On this issue, I was happy to see in the gap analysis actually, this was a recommendation in that -- in that paper there came out from the -- and, you know, so this is definitely on, at least, probably -- radar. And, you know, had some interaction with them, and I mean, I totally agree with you. It's a solvable problem, and I think there's increasing awareness.

MR. GARCIA: Definitely alleviate some headaches from lonely data analysts forecast information.

Okay. Let's see. I would like to invite the IOUs up, and as well as LADWP or SMUD. Let's see. Let's switch the order and let's see if there's folks on line that would like to comment first. Should be possibly Southern California, Edison.

Or please indicate if you have no comments.

Silence is an indication.

You should be able to speak if you're on the line.

I think our volume's a little low. Hold on Hunyang. It's very faint. I think it's a problem on our end. Give us one second.

Can you try again, Hunyang.

No. We're still having trouble.

Okay. Well, my master plan to start off with people on the line, totally blew up in my face. So sorry, Hunyang. We're going to have to reconnect. I'm going to go towards the folks in the room now.

CHAIR WISE MILLER: Yeah. I would say one possibility is if Edison were to send, say, either an email, that she could read it for you, right?

MR. GARCIA: Hunyang, if you're there, another option is to send IEPR team an email or WebEx as well, and they can read it out given the technical difficulties we're having.

All right. I see PG&E and staff there. I'm going to invite you guys up. You can start if you have any comments to provide either on -- either on this planning area results or --

MR. MOAZED: Yeah. Ali Moazed with the resource forecasting team at PG&E. I just wanted to say that we appreciate staff's cooperation and commission's attention to these issues. I don't have any comments at this time, but we definitely look forward to working with you on improving the CRA forecast and the workshops and resolving some long-term uncertainty and planning around that.

So no comments at this time, but we, we will take advantage of the comment period and final written

comments. So thank you.

MR. GARCIA: Yeah. And I hear you have a new forecasting team coming together. So we'll look forward to working with you guys. We'll have to do a meet and greet.

Ken, looking at you. San Diego.

MR. SCHIERMEYER: Ken Schiermeyer, San Diego Gas and Electric. The only comment we have -- we're going to reserve the, the written comment period. Once we have a little more time to review the data and once, once -- especially, once the forms come out early next week, it will give us a little more time to digest, you know, the information, but I want to thank the CEC staff for, for working with us, and also, for, for the 2008 update. It seems like we're updating more information like the EV and the PV. So that's -- I think that's greatly appreciated. Those tend to be the technologies that are moving the needle in the forecast. So that's appreciated. So look for comments from us in written form.

MR. GARCIA: Is somebody from SMUD in the audience that would like to comment?

Nope.

LA DWP in the room or on the line?

All right. Should we try Hunyang one more time

or read her comments?

MS. RAITT: "SDE would like to thank commission staff for their collaborator efforts with SDE forecasting team. We would like to offer a few high level comments at this point before further examining the detailed report."

That's all I have right now.

"First, the peak shift results for SDE are still puzzling to us. It is contradictory to what SDE observed. SDE have seen late afternoon loads stay strong and expect peak hours to shift to much later hours."

MR. GARCIA: Okay. I would also -- last but not least, I would like to invite Siva up if he would like to provide us some comments and then after Siva, go back to --

CHAIR WEISENMILLER: I was actually going to say, are there any -- before -- just before, is there any public comment?

MR. GARCIA: Oh.

CHAIR WEISENMILLER: And in general, anyone other than utilities, obviously, is welcome.

MR. GARCIA: That's a good point. I get too distracted.

CHAIR WEISENMILLER: Oh, no. It's fine.

Heather, do you have something to read from someone?

MS. RAITT: I wasn't sure if we were in the public comment period. So I have two comments from Brian Kolodji from Black Swan Technologies, and I will read them. The first one is -- he goes -- it starts,

"ZEVs are expected to replace gasoline driven cars if a carbon neutrality is to be achieved in 25 years, 2045, per Governor Brown's executive order B-5518. For the California Energy Commission, the total system electric generation produced in state by California 2017 is 206,337 gigawatt hours. The concern is that if all gasoline driven cars are converted to electric driven zero emission vehicle cars, then 15.1 billion gallons of gasoline energy must be provided regarding -- or as approximately 663,717 gigawatt hours. This adds more than triple the electric power required by the total California system electric generation to the total California system electric generation. In other words, when ZEVs replace gasoline driven cars, the power required in California's total system power ranges from 200,000 gigawatt hours to almost 900,000 gigawatt hours. How has the power required by ZEVs expected to be in place by 2045 been included in the forecast -- or

has the power -- excuse me -- required for ZEVs expected to be in place by 2045 been included in the forecast?"

And Nick Fugate was going to briefly address that.

MR. FUGATE: So I thank Brian for his question. Just a couple notes here. First note that 2045 is a little beyond the scope of the forecast that we have put together here. And then I just -- so we're looking at the 2030 for, for this forecast, for the IEPR forecast. And I'll just reiterate a few points from Aniss' presentation earlier this morning. So our current ZEV forecast in the reference case is looking at 3.64 million ZEVs by 2030, and in our highest case, 5.47 million. And for the reference case, the PEV portion of that is expected to contribute about 16,000 gigawatt hours of additional load.

MS. RAITT: Thank you. Okay. I'll read his second comment.

"In 2017, renewable energy derived power inside California is 61,183 gigawatt hours or about 30 percent. Natural gas derived power inside California is highest at 89,564 gigawatt hours or 43 percent. These percentages reduce by one quarter of ZEVs implemented.

In other words, if we are to achieve carbon neutral, renewable energies such as wind, solar, and hydro and not by amassed, must be used. Can this type of renewable keep up with the demand and its additions for ZEVs? I suspect not as the IEPR currently shows only a nine percent reduction over 20 years of, of -- excuse me GHG 40 million tons out of 500 million tons. With ZEVs, this nine percent drops to two percent, and it is unlikely that the renewable energy would be able to provide the 98 percent required over the 25 years, by 2045.

Would CEC consider utilizing capture from natural gas or biomass power plant stacks to help meet carbon neutrality goals, zero growth of carbon in the atmosphere. Bio-sequestration technology such as crop enrichment can achieve the carbon neutral goal earlier than 2020."

So, again, that was Brian Kolodji from Black Swan Technologies.

CHAIR WEISENMILLER: Again, the simple response is the, the Governor's executive order will be worked into the next governing plan; certainly not now. And at this point, we're looking at demand forecast as opposed to -- but, you know, again, it's certainly good

questions. But longer-term questions that would be a big issue, I think, in 2022 scoping plan.

MR. GARCIA: All right. We're going to try to open the phone lines one more time. It sounds like we have Ed Martinez from Southern California Edison on the line.

Ed?

MR. MARTINEZ: Hi. Can you guys hear me better than Hunyang?

MR. GARCIA: Yes. I can hear you way better.

Huang, if you have Ed, Put Ed on the line. He came in pretty clear. You're still, kind of, muted.

MS. SHANG: Am I still muted? I'm actually using Ed's line.

MR. GARCIA: Oh, perfect. We got you loud and clear.

MS. SHANG: Okay. All right so my name is Hunyang Shang. I'm manager of demand area forecasting in the southern California Edison. I'd like to offer a few quick comments.

First of all, I'd like to thank commission staff for their collaborative work with SD forecasting team. Some area I'd like to point out to you is with regard to the peak shift -- I really appreciate Chris Kavalec

taking to SDE's comments with that being the most recent hourly load history from SDE to the results that Chris was showing earlier is still puzzling to SDE as we have observed our hourly load, especially in the late afternoon, stay stronger than before. And so we would like to further explore the approaches and examine the results with CEC, and this greatly impact CEC peak demand forecast.

Second, I'd like to comment on is with regard to the long-term RA load forecast. As Chris showed earlier, the monthly peak load shape at the TAC level, it looks reasonable to SDE. However, we like to better understand the future process between IEPR monthly peak forecast and each LSEC monthly peak load forecast for our members as we will have many LSECs utilities serving loads within each TAC area.

And the third comment is with regard to the sales forecast. We made a quick observation with CEC staff that our SDE overall sales forecast growth looks reasonable. However, the first forecasting point in 2018 is different than SDE have picked out from the actual. Our sales remain rather flex in 2018 compared to 2017. Different than what CEC reflected in the decline. So that's my overall comment.

MR. GARCIA: All right. Thank you, Hunyang.

I think that's all of it.

MR. SIVA: Goof afternoon, commissioners and Neil. Thank you so much for being here. As a team, we just wanted to extend our thank you to all the commissioners for the guidance as we tried to put together the CS forecast and also try to dissolve a number of different issues that, that came up at the forecast. I also want to extend my thank you to the JASC members, especially Simon Baker and Jay McCannon, who is here from CPUC for their input and feedback. I want to extend that to Delphine and Amber Motley from CAISO for their feedback and also to quote from Aniss, "takes a village to raise the forecast." I, specifically, wanted to thank Chris Kavalec, Cary, and Nick for their incredible effort this year to pull a lot of weight just between them to make the forecast happen. And I also wanted to acknowledge the delay on developing the report as well as putting the forms out for public consumption. We are going to try to do it in an expedited fashion, hopefully, this week or early next week and, and hopefully have discussions with the LSE and continue to have discussions with CPUC and CAISO on resolving any discrepancies. So I just wanted to close that. Thank you so much.

MS. RAITT: so I think that's it for, for

the agenda if you had any closing remarks.

CHAIR WEISENMILLER: No. Again, I'd like to thank people for their participation. Certainly encourage everyone to really dig in. The information was posted. You know, certainly, also going to encourage the CAISO and PUC to dig in on any information you have on the Edison peak shift question, you know, in terms of what the shapes look like so that we can try to get on top of that issue. Certainly, I think again certainly encourage the Edison in terms of informational stuff. Bottom line, this is important. We're trying to really do it right and looking for people's help to go through the process. There's a lot that came out today. We'll be flushed out more fully early next week, and we just really want everyone to dig into it, and certainly, you know, as I said, if the people need more time between when everything is posted or if they need a webinar or whatever it is so that we can really dig into stuff, but certainly let us know. At this point, Heather will certainly repeat when -- as she has -- when written comments are due. And Chris indicated, you know, there's been this tradition of suddenly finding the forecasters working through the holidays, but certainly, comments earlier than later would be appreciated by them.

COMMISSIONER RANDOLPH: I will just echo my thanks to Siva and everyone here who have been working really well with our staff. You guys have done a huge amount of work and have been very interactive and very receptive to feedback, and I think it's been a good experience, and we hope to, sort of, continue the dialog as we go forward and try to avoid having you guys work over the holidays.

COMMISSIONER MCCALLISTER: Okay. Go ahead.

MR. MILLAR: And on behalf of the ISO, I'd just like to echo those comments. We really appreciate the extra efforts especially on the hourly load shape issues. That really moves the ball down the field for us. Thank you very much.

COMMISSIONER MCCALLISTER: Great. So, you know, I'll chime in here with, with equally positive feedback for staff at all three agencies, and also just highlight that RA, you know, discussion is a -- it's a analytical discussion about the forecast, but it's also a process discussion. And, you know, each agency has its own, kind of, process it has to fulfill and ideas about how to make things more robust from their perspective. So I think taking into account, you know, of those -- really, their administrative or regulatory questions in each agency. You know, making sure that

we're keeping it real and relevant for those discussions as well is important. So I think that dialogue is even more critical to, you know, ensure that we don't go off track just in a practical way and just be pragmatic about it. So thanks for keeping it going.

COMMISSIONER HOCHSCHILD: This is not easy to do well. In fact, I think the job gets harder over time. There's all these new -- even just walking to lunch today, all these new electric bikes and other two-wheeled electric devices that are proliferating around the state. It's very difficult to accurately forecast the rate of the growth on these, but the stakes are obviously really high for a lot of reasons that we get this right. So I really appreciate all the agencies, and thanks, everybody.

CHAIR WEISENMILLER: We're good. Adjourned.

(Whereupon the proceeding concluded at 2:08 p.m.)

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I, Brittany Flores, a Certified Shorthand Reporter of the State of California, duly authorized to administer oaths, do hereby certify:

That the foregoing proceedings were taken before me at the time and place herein set forth; that a record of the proceedings was made by me using machine shorthand which was thereafter transcribed under my direction; that the foregoing transcript is a true record of the testimony given.

I further certify I am neither financially interested in the action nor a relative or employee of any attorney of party to this action.

IN WITNESS WHEREOF, I have this date subscribed my name.

Dated:

_____

Brittany Flores CSR 13460