DOCKETED	
Docket Number:	18-IEPR-04
Project Title:	Energy Demand Forecast Update
TN #:	224311
Document Title:	Transcript of 07102018 Lead Commissioner Workshop
Description:	IEPR COMMISSIONER WORKSHOP ON THE 2018 CALIFORNIA ENERGY DEMAND FORECAST UPDATE
Filer:	Cody Goldthrite
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	7/27/2018 8:54:43 AM
Docketed Date:	7/27/2018

CALIFORNIA ENERGY COMMISSION
IEPR LEAD COMMISSIONER WORKSHOP

In the Matter of:	) Docket No. 18-IEPR-04
	)
	)
	) LEAD COMMISSIONER
	) WORKSHOP
	)
2018 Integrated Energy Policy	)
Report Update	)
(2018 IEPR Update)	) Re: Energy Demand
______________________________	) Forecast Update

NOTICE OF IEPR COMMISSIONER WORKSHOP ON THE 2018
CALIFORNIA ENERGY DEMAND FORECAST UPDATE

CALIFORNIA ENERGY COMMISSION

THE WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM - FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA 95814

TUESDAY, JULY 10, 2018

10:00 A.M.

Reported By:
Peter Petty

APPEARANCES

COMMISSIONERS & ADVISERS:

Robert B. Weisenmiller, Chair, Lead Commissioner for Electricity and Natural Gas

J. Andrew McAllister, Lead Commissioner for Energy Efficiency

Ken Rider, Advisor to Commissioner Hochschild

Matt Caldwell, Advisor to Commissioner Scott

STAFF:

Heather Raitt, IEPR Program Manager

Chris Kavalec

Nancy Tran

Aniss Bahreinian

Sudhakar Konala

Miguel Cerrutti

Nick Fugate

PRESENTERS:

Ali Moazed, Pacific Gas and Electric

*Eduardo Martinez, Southern California Edison

APPEARANCES (CONT.)

PUBLIC SPEAKERS (* Via telephone and/or WebEx)

Delphine Hou, CAISO

Erica Jue, Silicon Valley Power

Olof Bystrom, SMUD

I N D E X

I N D E X (Cont.)

P R O C E E D I N G S

JULY 10, 2018 10:02 a.m.

MS. RAITT: Good morning, everybody. Welcome to today's IEPR workshop on the 2018 Demand Forecast Update.

So our meeting is being broadcast by our WebEx record conferencing system, so we will have an audio recording that will be posted in about a week. And we're also going to have a written transcript of this meeting and that will be posted in about a month.

At the end of the day, we'll have an opportunity for public comments. And we'll limit those comments to three minutes per person. All the materials for this meeting are posted on our website and hard copies are available at the entrance to the hearing room.

If you did want to make a comment at the end of the day, go ahead and just give me a blue card and we'll go ahead and set that up and you can comment at the center podium there. And for folks on WebEx, just use the chat function to raise your hand and let us know and we'll open up your line at the end.

Written comments are welcome and they and they are due on July 24th. And the notice gives you all the information on how to submit written comments, but again July 24th for written comments. Thanks.

Go ahead.

CHAIRMAN WEISENMILLER: Great. I'd like to thank everyone for being here today. I appreciate the opportunity to get a lot of input on our update of the Demand Forecast. The Demand Forecast is one of the more important parts of the IEPR since it provides the foundation for planning activities both at the ISO and PUC. So anyway it's really important to get it correct.

This year is an update. So a lot of what we're going to do is sort of correct for some of the new data on things like CCAs, or PV, on rooftop or SAV, (phonetic) things which were pretty hard to do a long-term forecast. But we're also going to look at some of the structural issues that came up from last year's hourly forecast model. The good news is we got it done. It was generally correct although there were a few glitches, so it's good to talk about options on that. Thank you.

Andrew?

COMMISSIONER MCALLISTER: Yeah, so not too much to add, but I think also it's good to keep in mind the context here, sort of the longer-term context where the move to an hourly forecast was a big deal. And as we move towards IRP, and as we move towards the doubling efficiency goals and the EV goals and we try to get more local and more geographically specific in that work, even beyond and outside of the forecast and just the programmatic environment we need to link those over time and learn how to link them to the forecast.

And so the forecast is both getting more granular, more detailed temporarily, but also occasionally are parallel challenges that are going to take several cycles to kind of figure out and get dialed in. So that methodological evolution will be ongoing and sort of this update is, I think it's wise to see this update in that context.

But that's all I had to add. Anyone else?

MR. RIDER: Yeah, I would just maybe echo what the Chair said. It's a really interesting time in California's grid, with a lot of exciting new trends with PV and EV, but also really complex new trends like who will serve the load and is it going to grow or are our retail sales decreasing? So yeah, I look forward to the discussion.

MS. RAITT: Okay. So our first presenter is Chris Kavalec, from the Energy Commission to give an overview of the forecast.

MR. KAVALEC: Good morning. I'm Chris Kavalec from the Energy Assessments Division. And I'm going to start us off with an overview of the forecast update, what it's composed of, why we do it and the process and timeline that we have set up for this.

A little bit of background. The illustrious three agencies have been sitting down and planning collaboratively, so that all the major proceedings are in sync, so there's no delay in any of the products that come out of these proceedings. And during these discussions, back a few years ago, we recognized a need to have an IEPR Forecast Update in the even-numbered years and we started doing this in 2014. And the main purpose of it was for the California ISO's Transmission Planning Process, which is an annual process, so a forecast update was deemed necessary. It also serves as a handy refresher for any of these other important processes listed here, including distribution level planning.

Originally, we agreed to a very limited IEPR forecast update, where we were just changing the economic and demographic indicators to account for the passage of one year, as well as updating the historical data for sales, consumption and peak demand. And we were going to make no updates to any other demand-related factors. That was going to be left for the long-term forecast, during the IEPR years. And this was being done for electricity only.

And basically, the method that we used is we estimate single equation econometric consumption models for all the major sectors listed here. And then we run each model with the old and the new economic demographic indicators. And we apply the percentage differences yielded from that estimation to the 2017 forecast, or the previous long-term forecast.

For the update this year, we agreed to update to what I'm calling dynamic components, because there's a lot of action in these areas: the EV forecast and the PV forecast, including a new element we added in the last long-term forecast additional achievable photovoltaic adoptions.

And as the Chair mentioned, there are some adjustments that need to be made to the hourly load model as well as the Residential TOU Analysis that we did for the first time in the last long-term forecast. We will be discussing these later.

And what we get at the end of this process is an Updated Baseline Forecast for electricity sales, consumption and peak demand for 8 planning areas and 20 climate zones. As in the long-term forecasts we do three demand scenarios: high, mid and low. The efficiency, including AAEE, Additional Achievable Energy Efficiency, will not be changed from the last long-term forecast. And as in the long-term forecast we provide what we call managed forecasts, for use in resource planning. We do two of those, one for system-wide planning and one for more localized planning. And that's the combination of our new midline baseline case, with the mid and the low-mid AAEE and AAPV scenarios.

Okay. Process/milestones. We have two DAWG meetings in the near future. July 12th, we're going to talk about our EV scenarios as well as developing new EV charging profiles. And on August 2nd, we'll be talking about methodological issues like the hourly load model and weather normalization and so on. We'll be developing our final Econ Demo Indicators, which we'll talk about today and updating the historical data in the next couple months.

We'll be developing the actual forecast in October and November.

We'll have a workshop in early December to present the results.

And we will address and incorporate any final comments during December, post a final report at the end of December. And if all goes well, we'll have the forecast update adopted in early January.

So any comments on the overview, before we get the meat of the workshop?

CHAIRMAN WEISENMILLER: No. That's pretty good, Chris. Thanks.

MR. KAVALEC: Okay. So our next presentation is on Econ Demo Indicators. And before we get to that, I wanted to give a few factoids on the California economy. I don't have a slide for this; I just sort of thought of this at the last minute.

But as we know, the California economy is growing at a pretty healthy clip right now. GDP growth was 2.8 percent last year, growing faster than the United States, as a whole. Depending on who you read, we're in the longest or second longest period of sustained economic growth in modern history. Unemployment in the state is at historic lows. But, as always, there are some danger signs that economists are watching. For example, looming large federal budget deficits could increase interest rates and suppress economic growth.

The President's moves in trade could affect California more than other countries.

(Off mic colloquy.)

MR. KAVALEC: No. I don't have a slide for this. Sorry.

The President's moves on trade could affect California because we have the largest port complex in the country.

Also, as we know, we have housing shortages. And the growth that we're seeing is more balanced toward the coastal side than the inland side. So Inland California suffered worst during the recession and they're not growing as quickly as the coastal areas in our now booming economy.

The Los Angeles area, unlike past years, is really pushing a lot of the growth, in California, because of leisure and hospitality information and construction. So that's just a brief summary.

And I'll just mention that no economists are yet, or economic firms are yet, predicting a recession for California. So at least in the short term. So with that, I'll turn it over to Nancy Tran, to talk about our Economic and Demographic Indicators.

MS. TRAN: Good morning. My name is Nancy Tran from the Energy Assessments Division and I will be discussing the economic and demographic drivers and scenarios.

Economic growth or lack thereof has been a key determinant in changes in electricity consumption. For example, this graph clearly shows the impact of the economy on electricity consumption by plotting statewide employment alongside consumption over the last couple of decades. This also shows the impact of a recession over energy demand as you can see with the arrows indicated in the 1990s, 2002 and 2008.

The effects of the Great Recession are particularly apparent as both employment and consumption take a large dip in the beginning of 2008. Although economic growth will continue be a key factor, we do see some decoupling of electricity consumption and the economy in recent years as efficiency and to a less extent rate increases have flattened consumption while the economy continues to grow.

The forecast uses various sources of data information. We use these resources in particular for the California Energy Demand Forecast.

Here, we have a quick look at all the various scenarios from our resources for personal income in 2017 dollars. You'll notice the multiple scenarios from IHS Global Insight, UCLA Anderson Forecast and a variety of scenarios from Moody's Analytics, about 10 of them. You can see noted in the legend as S0 to S8, as well as a consensus scenario.

These scenarios incorporate a variety of different assumptions. You can see the spread between the highest and the lowest in 2030 is over 7 percent.

And here is a variety of scenarios for the same sources, for employment. You see the spread between the highest and the lowest in 2030 is a little over 8 percent.

And here's manufacturing output in 2009 dollars. You can see the spread between the highest and the lowest is almost 20 percent.

These are the other key economic drivers we use in the forecast besides the three that I already discussed.

These are inputted into our forecasting models. We have three scenarios: high, a mid and low demand scenarios for each driver.

We have worked with Moody's Analytics to develop a more customized high-demand scenario for us. The reason for this is the Moody's current optimistic scenarios are very close to the baseline. Therefore we work with Moody's to develop a higher growth scenario that reflects significantly higher growth overall than their baseline, while remaining internally consistent with the other scenarios that we use.

So we went from a multitude of different scenarios to create three: the high, mid and low demand scenarios. So this is just an update for the forecast, we want to use scenarios consistent with the 2017 forecast. So here, we're using Moody's baseline: the special high-demand scenario and a lower, long-term, growth scenario, as we did in the 2017 forecast.

This graph shows the two scenarios minus the high-demand scenario, because that's currently in development. So based on this comparison of the old and the newer mid case for personal income, the mid-residential baseline forecast will be slightly lower and all else equal.

So this is total employment and it is the same methodology that we use. So comparing the mid cases for employment, it looks like a slightly lower mid baseline commercial forecast.

And on the other hand, here's manufacturing output. And it's growing faster in the new mid case. Therefore, we expect a slightly higher industrial mid baseline forecast.

And this is total population, with the old scenario and the new scenario, using updated California Department of Finance data for a total population. We used this scenario only for the 2017 forecast and we are going to be consistent for the 2018 update and we're going to use the one new scenario as well. You'll notice that the little to no change.

Any questions?

CHAIRMAN WEISENMILLER: Yeah, I was going to say, I want to thank you and Chris for this presentation. A couple of questions.

One is what, as you go through the various data sources, what's the quality of the data at both an aggregate level and then as we go to more and more geographical disaggregation? Where are our limits on data as we get more and more disaggregated?

MS. TRAN: Well, we use the data at the county level. And that's as disaggregated as we can possibly get, with the data being as great as it can be. If we get any lower, we might run into some issues.

CHAIRMAN WEISENMILLER: Right. Okay. And do we look at the Department of Finance Forecast?

MS. TRAN: Yes.

CHAIRMAN WEISENMILLER: Okay. I know they -- how different or similar are they to the ones (indiscernible)?

MS. TRAN: Well, the Department of Finance, we requested that they create special scenarios for us too. We haven't gotten those for the new forecast. But they're pretty much in line with Moody's and IHS Global Insight as well as UCLA. UCLA uses Department of Finance in their forecasts.

CHAIRMAN WEISENMILLER: Okay. Good. And one of the things that was CMTA earlier, just well back in June, they were saying what they found is there's obviously been a very big growth in the service industry in California. You know, it wasn't that long ago that Facebook or Google or Apple, I guess Apple anyway, that they didn't really exist and now they're among the largest companies in the world. While they see a real disappearance of the classic manufacturing part of the California economy, you know.

And basically when you look at relative rates across the country again, we have relatively higher rates for industrial sector. So that the obvious tendency is to try to reduce your bills and if you're a very, very energy intensive probably the only way to really reduce your bill is to move. So how's that sort of structural change being reflected in our forecast? Chris?

MS. RAITT: Chris, would you like to take that one?

MR. KAVALEC: Well it's a couple of things. Moody's projects shifts in structure of the industrial base and that's mainly what we rely on. But we also, our industrial forecaster spends a lot of time looking at individual subsectors, like chemicals and metals and trying to project trends. Not only moving in and out of the state, but more or less energy efficiency processes. So but both the Econ Demo Forecast and work in-house, we try to account for that.

CHAIRMAN WEISENMILLER: Okay. No, that's great. I was just going to end by saying I think the Governor's metaphor for the economy in this area is "winter is coming".

MR. KAVALEC: Yes. That is true.

CHAIRMAN WEISENMILLER: Yeah, that this is the longest period without a recession in at least recent history, if not going back a long, long time. So the anticipation is some sort of downturn is coming. And we'll see how that plays out.

MR. KAVALEC: Yeah, and like I said, we don't have anything specific predicted yet by any of the prominent economists. But on the budget itself we've seen the sort of flattening of the stock market in the last few months, as opposed to last year when it was booming.

And the California tax structure is set up so that it depends a lot on the high income earners who tend to be the ones involved in the stock market. So if the stock market starts to drop, then we could see a quick reduction in the tax base and emerging budget issues.

CHAIRMAN WEISENMILLER: Yeah. My impression is at least there's some indication in the bond markets that things are getting closer to the end.

MR. KAVALEC: Uh-huh.

CHAIRMAN WEISENMILLER: Thanks.

MS. RAITT: Thanks. So next is Aniss Bahreinian from the Energy Commission on electric vehicles, Light-Duty Electric Vehicle Scenarios.

MS. BAHREINIAN: Good morning Commissioners, stakeholders. I'm presenting our perspectives on the scenarios and the California economy. We are focusing on the California PEV market and the presentation is focused on that. And at the end, we're going to talk about the different changes that we are going to consider in the forecast.

We should notice that scenarios that we discuss here is very brief, because we have a DAWG meeting on July 12th, where we are going to discuss more specifics of the scenarios with the stakeholders, utilities, OEMs and others in the state agencies.

This is slide -- we are focusing again on California, because the California economy is very different from the national economy. California PEV market is even more different from the national market and so that's why we are focusing on California when it comes to the actual historical data here.

This is the data from the California New Car Dealers Association. And what they show is that new light-duty vehicle sales are declining, have declined, actually started to decline in 2017. And it seems like in the first quarter they continue to decline. Keep in mind that quarterly data, or the LDV market is a seasonal market. So the first quarter is not necessarily an indication of the entire year. Nonetheless, we see a decline quarter over quarter.

As we can see here in 2009, which was the Great Recession we had a pent-up demand. And the pent-up demand has been catching up with the continued economic growth. And in 2009, it has peaked to 2.09 million vehicles sold in California. But since 2016 it has been slightly declining.

The new vehicle sales are important to the PEV markets, because most of the makes and models, the PEV makes and models, are new vehicles. And so if there's a decline in the new vehicle sales we would expect to see an impact on the PEV sales as well.

In this graph, you could see that there is also a decline in the used vehicle sales in California, but the decline in used vehicle sales is almost half as much as the decline in the new vehicle sales. So the new vehicle sales have dropped more significantly than the used vehicles.

The good news is however is that despite the decline in new vehicle sales, PEV sales continue to grow. And in this graph we have the market share of hybrids, as well as the market shares of PEVs and PHEVs here. I notice you can see that this -- a continuous decline in the hybrid sale shares here indicating that some people are moving from hybrids to the PEVs. On the other hand the PHEVs and the EVs are increasing, indicating again that people may be moving, are moving.

Consistently, the UC Davis study that was done a couple years ago are moving from hybrids to the PEVs. But that's not the only reason why hybrid sales are declining. In 2014, as you can see, there is a decline start in 2014 and in 2014 is when we had the oil prices going down. With the decline in oil prices, then obviously demand for energy efficient vehicles can decline. So while some of the hybrid sales have been going over to the PHEVs and PEVs, some of the decline is also due to the decline in oil prices.

Notice however, that the sum of the market shares of hybrids and PEVs and PHEVs are at 9.6 percent in the first quarter of 2018. And if you look at 2014, they were also 9.5 percent. So the sum of the market share of the hybrids and the PEVs have not changed much. They have increased by 0.1 percent. But the distribution between these vehicles have significantly changed since 2014. Notice also in this graph that you see PEV sales are higher. In 2014, they start to be higher than the PHEVs, but the PHEVs seem to be catching up. This depends on the price and the makes and models that are offered in the market. But still, electric vehicle registrations in 2018 exceeds the PHEV registrations in 2018.

We said that the California market is special. Well, this is also another trend that we see in the California market. We also see that in the national market, but it is greater in California, and that is the light truck sales are exceeding car sales in the first quarter of 2018. They begin to exceed the car sales in the first quarter of 2018. Light trucks include SUVs and crossover SUVs. So there's clearly an increased preferences for these vehicles in California, both in the commercial market and in the residential market, in the households.

The good news however, is that -- and we have been, by the way, our surveys have been confirming this. In the past two rounds of the surveys have shown that the larger vehicles are more preferred to the smaller vehicles. And we see the results now in the market.

The good news however is that for all of these discussions that have happened in different IEPRs, people also take note of what we say. And for instance, Ford manufacturer, the Ford Company is now in response to the market changes, are discontinuing all of their car productions in the U.S., all but two of them. And then focusing on the light truck production while at the same time, they are producing cars in other countries, indicating again the differences between the U.S. markets and other markets and between California market and other markets.

The good news is, however is that as you can see in this number of makes and models that have been announced by different manufacturers, there is a rise in the number of makes and models that will be offered that are due to be offered in the U.S. in California until 2022.

Notice that the number of light trucks has been on the rise both in the PEV section and in the PHEV section. Notice, very importantly, that the PHEVs in the light truck in 2022 based on the announcements of the OEMs exceed the announcements of cars, in the PHEV. So that's good news, which means that the markets are responding to the consumers. And actually the revolution that started in California under light duty vehicles compact with Leaf in 2010 has now crossed over to other larger vehicles and to other sectors like MD and HD vehicles as well. So all those technological revolutions that we have California to thank for has been spreading over to different classes of vehicles.

Not only that, it is also spreading over different modes of travel. Like for instance, you see the E-bikes feel in Sacramento and it is expected that by the end of summer Sacramento is going to have the largest fleet of E-bikes, which is called Jump, in Sacramento. So we see that there is a mode crossover and there is a class crossover. Technology is moving on and responding to the market.

Now if you look at this table again from the CNCDA first quarter, what we notice here, the point here is that the share of the Detroit Three is now at 29 percent for the new vehicles and only 36 percent in the used vehicles.

What this is telling us is that the majority of the vehicles that are purchased in California are actually foreign models. The significance of this is when you think about trade policy. So it is important to consider trade policy when we are looking at the scenarios in California, because the current tariffs on foreign cars is going to increase price of cars in California. Current tariffs on steel is going to increase price of vehicles in general. Steel and aluminum is going to increase price of vehicles in general and also automotive parts.

So it is going to have a significant impact on the car culture of California and on California economy, all these protection policies, as well as the trade war that has actually started.

Now, how about the scope of forecast? The scope of forecast is going to be on PEVs. So we don't generate the forecast of the electrified vehicles in other sectors. We are only looking at the light duty vehicle sector. It is a dynamic market, as Chris pointed out. And what that means is a lot of the inputs may have changed. We are going to have the same scenarios that we had in 2017. They are defined in the same broad scenarios that are defined in the 2017 with the high, mid and low, consistent with forecasts in other parts of the Commission, in the rest of the Demand Analysis Office.

However, like everybody else in the Demand Analysis Office, we are also going to use new projections of income, new projections of population and we are going to include new projections of fuel prices. Fuel prices, as many of you know, have increased, have been increasing. And actually the current fuel price is higher than our high forecast last year. And that has implications of course, for purchases of cars and consumption of fuel in California.

We are going to use 2016 American Community Survey, 2016 is going to be our new base year. And what it shows, the 2016 American Community Survey shows an increase in income and an increase in the number of multi-vehicle households. That is important to us, because the more multi-vehicle households you have the more PEV sales you have. Our survey shows that preferences for PEVs are higher for households with more vehicles. It changes not very significantly between 2015 and 2016, but nonetheless it's going to have a positive impact. Likewise, the increase in income is going to have positive impact on the model, on the sales of vehicles in California. And therefore we are going to use the new 2016 American Community Survey in our base year data.

They are also going to change the vehicle attributes. For the most part we are going to keep them the same except for the PEVs. We are going to change the price projections for PEVs, the range projections for PEV and the number of makes and models, because there have been changes. Even some of the models that have been announced in 2017 at higher price and lower range are now revised. A couple of the models have been revised to lower the price and increase the range in addition to the fact that new makes and models are being introduced into the market.

Therefore, we are going to incorporate new forecasts for vehicle price, range, number of makes and models, as well as time to station because with the Governor's Executive Order, which is setting the goal for the number of charging stations in California to 250,000 time to station is expected to decline. And we are going to take that into account.

We are also going to -- we have a regional model, our main model. Number one, I should say that when we are generating this 2018 Forecast we are going to run the entire model. So we going to use the new inputs and we are going to run the model. We are going to see the results. The model itself doesn't change, but the inputs to the models have changed. And we are going to use new inputs.

However, we also have a regional model, which is post processing the statewide forecast that we generate. And we are going to generate a new model for that regional forecast. We are going to use the latest set of data to reflect the latest changes in the market. So we are going to use the 2017 data that we have in order to re-estimate our regional model and take advantage of the changes, the regional changes that have happened in California.

When it comes to policies there are -- the main ones are of course the state rebates that, because of the Governor's Executive Order, is going to extend to 2025. And in the past we had it as stop I think in 20 -- earlier in the forecast. But now we are going to extend that to 2025, in the low demand case. In other cases, they were already in 2025.

We are also going to take into account the federal reversal of CAFE and the ZEVs in the low demand case. MPGs for all of our ICE vehicles are going to be capped at 2021 levels, so after 2021 we are going to hold the MPGs for all the ICE vehicles at the same level, after this reversal of CAFE.

The CAFE can also have impact on how the manufacturers are going to respond to these standards by increasing EV production, but we don't have a way of considering that except for our number of makes and models that will be offered in the market. So that's going to be taken care of there.

Federal Trade Policy, we think is going to have a significant impact, but it is also all of these are going to cause a lot of uncertainties. So the name of the game for this forecast is increased uncertainty. We don't know how long this trade war is going to last. We don't know how far it is going to extend. There's a lot of things that we don't know. What we do know is that presently we have the 25 percent tariffs on cars, on steel and 10 percent on aluminum.

How is this going to impact the market? If all of the EVs are made out of aluminum, and are subject to 10 percent tariff on aluminum, then obviously just metal compared to metal we would say that perhaps EVs will have an advantage over the ICE vehicles are mostly made out of steel.

We don't know how exactly we are going to account for this, because our model and the main model that we are running, doesn't account for the difference between foreign and domestic models. We have a generic class of model. We do not distinguish between them. So we have to devise a way, perhaps some weighted average, in order to incorporate these tariffs into higher prices, higher vehicle prices for different fuel types, different vehicles with different fuel types in the low demand space.

Any questions?

CHAIRMAN WEISENMILLER: Yeah. It seems like one of the key things, as we go through this in terms of back casting, is seeing that the quarterly updates. And so far we have the first quarter, which is obviously not a time of high sales. When would the second of third quarter data become available?

MS. BAHREINIAN: The second quarter actually I was looking at; I think it's going to become available from the CNCDA in a few days.

CHAIRMAN WEISENMILLER: Okay.

MS. BAHREINIAN: Perhaps, but I was just reading this morning that June sales were up. So there was an indication that there was an increase in sales in June, vehicle sales.

CHAIRMAN WEISENMILLER: Yeah. Because I'm really curious on the mix between zero emission vehicles and ICE.

MS. BAHREINIAN: Yes.

CHAIRMAN WEISENMILLER: And so trying to see how that trend plays out this quarter and then the second and third quarter would be helpful

MS. BAHREINIAN: Yes.

CHAIRMAN WEISENMILLER: I was going to note that one of the things that's consistent between McKenzie and also Bloomberg, is this sense that battery costs for ZEVs are reduced by about 20 to 30 percent a year, which is really always opening up the -- getting them closer and closer to parity. But pretty rapid change there. At least that was the message from both.

And also, I was just want to finally note that when the Beijing auto event occurred this year people were saying it was amazing how many SUVs, all electric SUVs were appearing on the market in China, or at least in that rollout. So really a shift from having very small cars, all electric cars in China, to much more consumer friendly.

MS. BAHREINIAN: Yes. Absolutely. And also speaking of China and the large fleet of electric buses that they have, which is supersedes everybody else in the world but California is also moving in that direction.

CHAIRMAN WEISENMILLER: Oh, yeah. No, we both are. I think a class that the Chinese have, like their sales are like a half million electric vehicles and this year, they're anticipating a million. So again they're a substantial fraction of the worldwide market on electric vehicles.

MS. BAHREINIAN: Very impressive --

CHAIRMAN WEISENMILLER: Of batteries -- as you said certainly buses, but also consumer vehicles.

MS. BAHREINIAN: Yes.

CHAIRMAN WEISENMILLER: Okay. Anyone else?

COMMISSIONER MCALLISTER: I guess -- early on in your presentation you talked about the market penetration for combined sort of clean vehicles sort of being roughly at 10 percent or a little below 10 percent pretty consistently.

Is your various scenarios, do they -- how rapidly or how much do they increase that portion of the market? I mean, to meet the goals we obviously need to go higher than that. And I guess I'm wondering how you're modeling that and forecasting that.

MS. BAHREINIAN: In the model, as you know, we do have substitution between different vehicles. So substitution takes place, but not to the same extent that was shown in this graph, so hybrids do not fall as fast as you would see in this graph.

On top of that, I should add that much of the hybrid movement is related to oil prices, too. And so with the increase in oil prices you could see again an increase in hybrid sales and there are also an increasing number of models that are offered in hybrid. So the picture that we have so far is not necessarily going to be the picture from now on.

COMMISSIONER MCALLISTER: Yeah. I guess I'm really interested in the evolution of the market, as the California consumer kind of starts to value the other attributes of EVs increasingly independent of oil prices. Like I hope that happens, because I think that disconnect is something that needs to happen in order to increase that market share. So that behavioral aspect, I'm really interested in how that evolves over time, which gets back to the numbers of sales by quarter. As they come in we can kind of try to understand that.

MS. BAHREINIAN: And actually that is captured in our survey and in our model by having higher preferences just for the fuel type, independent of the fuel cost, or any other attributes. California consumers have increased their preferences for PEVs and there's no question about that in our survey. So it is moving on.

MR. CALDWELL: Hi, Aniss. Thank you for your presentation. Just for starters, I'm looking forward to the DAWG meeting on Thursday to really dive into the PEV attributes that we'll be using on this year's forecast. So that should be a really interesting meeting.

Just a quick clarifying question, back on slide 5 for you, the electric line, does that include fuel cell electric vehicles as well?

MS. BAHREINIAN: No. Those are only the PEVs and PHEVs. California New Car Dealers Association doesn't publish much on FCV, so most of the graphs that you will see are on PEVs.

MR. CALDWELL: Okay.

MS. BAHREINIAN: We do have, in our own DMV data of course we have the fuel cell vehicles.

MR. CALDWELL: Okay. Thank you.

MS. BAHREINIAN: Sure.

MR. RIDER: Yeah, I have a couple of questions. First, when you say you're looking at revising the attributes of PEVs, you mean just plug-in, not battery electric vehicles, only the gasoline electric combination?

MS. BAHREINIAN: So PEVs, overall when we are talking about changing the attributes of the PEVs, we are talking both about PEVs and the PHEVs. So those two fuel types will be changed.

MR. RIDER: Okay. And another question I had was you mentioned the Executive Order for infrastructure, increasing the infrastructure and how that was going to trickle into characteristics in your modeling. To what extent is the target for ZEVs factored in to the policy used to drive the adoption model for vehicles. Because I don't know if these are backup slides, but there's three more slides. Are you going to -- I can ask a question then?

MS. BAHREINIAN: Sure.

MR. RIDER: If you -- are you going to present these?

MS. BAHREINIAN: No. I just left those, no I wasn't. I just left those for a new --

MR. RIDER: Okay, so on the last one there, the last backup slide?

MS. BAHREINIAN: Yes.

MR. RIDER: I notice the stock predictions in 2030, and I'm assuming that PEVs again means the combination of plug-in hybrids and battery electric vehicles. In none of these scenarios are we accomplishing our goals. And that's the difference between a goal and a forecast. I understand that that's a different thing, but it does affect the policies of the agencies and I'm just wondering to what extent that's factored into the kind of the policy push or incentives or anything like that? To what extent is the five million electric vehicle goal reflected in these forecasts?

MS. BAHREINIAN: When the PEVs stop in 2030, as you can see, in the aggressive scenario we are passing the five million. This is last year, by the way. This is not this year. We are passing the five million in the aggressive scenario.

And my guess is that we're actually -- our low, as I mentioned, the name of the game in this IEPR is uncertainty, uncertainty and more uncertainty. And what uncertainty means is that we are going to have a wider range between the different scenarios. Our low will probably be going to be lower than what we have here, but also our high is going to be higher than what we have here.

The three adopted scenarios last year were the low, mid and high. That's what we adopted. My guess is that we are going to move in the direction of the aggressive this year. And we are going to, most likely we are going to pass the five million that we have here. But that is going to be reflected. The way we achieve that is by lower prices, lower battery prices and lower electric vehicle prices. That's how we are going to incorporate different changes in the market.

MR. RIDER: Thank you.

CHAIRMAN WEISENMILLER: Yeah. Thanks.

MS. BAHREINIAN: Sure. Thank you.

MS. RAITT: Thanks.

Next we have a presentation from Sudhakar Konala, from the Energy Commission on behind-the-meter photovoltaics.

MR. KONALA: Good morning, Commissioners, stakeholders and members of the public. I'm going to present today about Behind-The-Meter Photovoltaic Systems and our Forecast Update for the 2018 IEPR.

So before I get into the forecast, I just wanted to go over some of the data sources that we use to capture all of the different information about PVs. So for each forecast update, we try to build a comprehensive data set combining all available sources of PV data. These include installed capacity, cost and rebate data as they are available and we classify installations by sector and subsector when possible. Finally, we also consider the date that the system was installed as well as the location in terms of the county, the electric utility, the planning area and the climate zone.

So as an example, I want to consider the data sources that we used to calculate installed PV capacity. So there's two types of data sets that we look at. First, is interconnection data and this comes from the form 1.8 IEPR filings that utilities do with the Energy Commission during the IEPR years and also the NEM currently interconnected data set that the CPUC publishes.

We also have Incentive Program data. The main one is the California Solar Incentive Program, but we also have the Self-Generation Program, New Solar Homes Partnership, Emerging Renewables Program and the SB1 POU Program data.

It's important to note that depending on the year, we use different sources. So a lot of the incentive program data we use for historical data from a while back. And we use the interconnection data for the more newer data. Specifically, not all the data sets are updated on a yearly basis. So for the 2018 update to get 2017 install data we're largely going to be relying on the NEM currently interconnected data set for that update.

COMMISSIONER MCALLISTER: Can I ask a clarifying question about that?

MR. KONALA: Yes.

COMMISSIONER MCALLISTER: So my understanding has been that the CSI Database, during the course of that program had really good data collection for every system. And so I know that, I guess. And there was a plan and I know it was partially implemented at least, but I kind of want an update to require the utilities to keep collecting that data for through interconnection. And so you've got that data set. How are those two data sets different? I guess what data are they not collecting in the interconnection process that they used to collect in the CSI Program?

MR. KONALA: From my understanding the NEM database is pretty complete. Except they don't collect information about systems that don't contribute to the grid. So if you have an entity that has a very high load throughout the day, but the PV system, all the energy generated by the system is used onsite, those systems are not reflected in the NEM Database.

COMMISSIONER MCALLISTER: Those are not NEM metered systems?

MR. KONALA: Yeah, They're called non-export systems.

COMMISSIONER MCALLISTER: Yes.

MR. KONALA: So I actually looked at the Form 1.8. They actually do account for the non-export systems. So when I looked back and compared the two data sets, I noticed that the difference between the two data sets is about 3 to 7 percent depending on the year.

COMMISSIONER MCALLISTER: Interesting, so are they still collecting sort of equipment data and sort of the details of the system that is installed behind-the-meter?

MR. KONALA: The NEM Database does.

COMMISSIONER MCALLISTER: Oh, great. Okay. Well, that's good. Thanks.

MR. KONALA: Okay. So I also wanted to review the 2017 Forecast before I headed into the updates from what we're actually seeing.

So as of 2016, the total statewide installed capacity was about 5,500 megawatts. In our forecast by 2030 we project this installed capacity to increase to roughly 11,600 megawatts, in the high electricity demand case, to 19,000 megawatts in the mid electricity demand case and 26,500 megawatts in the low electricity demand case. And I just want to remind that these are electricity demand cases, so in a low electricity demand case, we'll have high adoption of behind-the-meter PV.

So I'm going to move on to 2017 data that we have.

So looking at recent trends, in behind-the-meter PV installations we see that in 2017 new PV installations actually decreased from 2016. And the decrease was about 10 percent. This really isn't that surprising, because there was a spike in 2016 and probably even in 2015, because the federal solar investment tax credit was originally scheduled to expire at the end of 2016. So there were a lot of systems that were planned to be installed before the end of the tax credit.

So the tax credit has been extended. The full tax credit is available through 2019 and then it will be phased down slowly through 2021 before it's eliminated for residential systems after 2021. But when you're planning one or two years in advance, and you think the tax credit is going to expire, you're going to try to get it installed. So that's why we see a spike.

Looking at early 2018 data, we see that the market has stabilized and it's growing again, although not as fast as before. For January through April, installations for 2018 they're higher than 2017, but lower than 2016. And this data is only for the IOUs, which is what's available. Okay.

Next, I'd like to just compare the actual measured installations compared to what we forecast. So in two slides ago, I was showing total installed capacity, but on this slide I want to just show new installed capacity on an annual basis. And you can see in 2016 we did peak at least in the short term. And in 2017 we did come down a little bit. Now the gray line is the historical data. And the color dotted lines are our 2017 forecast. And as you can see, the actual new installations are actually pretty close to our mid case from the forecast. So this is actually encouraging.

Okay. So I'm going to move forward to more about the update now. So if you have any questions on the historical data, I can answer that. Okay.

CHAIRMAN WEISENMILLER: Yeah. So one question on data sources.

MR. KONALA: Yes.

CHAIRMAN WEISENMILLER: Is do we have any -- are we getting any data from the different cities that have mandated solar?

MR. KONALA: We don't get data from the cities, but the data sets, the larger data sets that I covered here, they do have zip code, city and county information in it, so we can disaggregate or I guess aggregate the individual systems, so we can show cities or counties or zip codes.

CHAIRMAN WEISENMILLER: Okay. Great.

Also, I was going to note the IRS did a recent ruling that gives sort of a three-year phase-in between start of construction for the solar and wind tax credits in terms of -- this is like they now allow a three-year construction period. We will docket the Keith Martin write-up on that. We realize there's not 100 percent sure on how much that is large scale versus residential, but that will at least give people a chance to dig into that.

MR. KONALA: Okay. Thank you.

Okay. Now, I'd like to get into what we'll be updating in the 2018 IEPR Forecast Update.

So the main thing we're going to update is just the historical data. We're going to include the 2017 PV installation data and I kind of covered that part already. We'll also be updating the econ and demographic data. And in terms of behind-the-meter solar, what really matters is the updated housing count.

We're also going to update installation costs and see if they've changed significantly from what we were anticipating. We're also going to look at new policies and regulations that have been implemented. And one of these is the new solar tariff that has been established on imported PV modules, the federal tariff by the Trump Administration.

So just as a recap, in 2018 there is going to be a 30 percent tariff on the module cost. And then this value is decreased by 5 percent a year through 2021 before it's eliminated afterwards. So the effect should be over the next four years.

When we actually get into the details though, in terms of behind-the-meter PV in the residential and commercial sector, we don't think it's going to have major impact. And I'd actually like to go through a figure that kind of clarifies this point.

So in this chart I have a data from NREL from early 2017. It is installed cost of solar for an average residential system and an average commercial system in California. So the first bar that you see that says "no tariff" that is NREL's data and they broke it down by components. So they actually broke it down far more than this, but I simplified it a little bit. So their estimate for module cost was 35 cents. And the rest of the system was $2.55.

So if we apply the tariff of 30 percent to the module cost that adds 11 cents to the overall cost of the total PV system increasing the price from $2.90 to $3.01. So for a typical residential system this is an increase of just over 3 percent. It's just not that high of a change to significantly affect adoptions.

Looking at the same process on commercial systems, the 11 cent tariff increases commercial systems from $1.84 to $1.95. This is an increase of about 5 percent. It's a good increase, but still not extremely significant.

One sector that our forecast doesn't cover, which is utility scale that is a sector that's probably going to be affected significantly because 11 cent increase, a utility scale costs about a dollar a watt installed. So 11 percent increase, you're looking at 11 percent increase in costs, so that is a sector to keep your eye on, going forward. But it doesn't affect our forecast, per se.

CHAIRMAN WEISENMILLER: Thank you. I was going to note, it's a little clear what the $50 billion of additional tariff, the tariff war will do, but there's some potential that that includes solar.

MR. KONALA: Yeah.

CHAIRMAN WEISENMILLER: It's a broad category about electronic goods. And there's some indication that might include PV as a second hit, but no one knows at this stage.

MR. KONALA: Yeah. And we'll definitely follow it.

CHAIRMAN WEISENMILLER: Thank you

COMMISSIONER MCALLISTER: I want to just point out. So actually, I want to ask what's in the gray, so you said they disaggregate a lot more.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: But that other, you know, was more than half the cost of residential system. And if that's mostly customer acquisition and sort of soft costs then that bodes pretty well for the declining costs in the Building Standards where now there are no customer acquisition costs and there's basically just equipment.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: And so anyway, yeah so I'm imagining that the cost allocation here of the different categories is different, a little bit, in California as compared to the other parts of the country? Is that a fair statement?

MR. KONALA: It is, but I can't speak to the specific details. I didn't look at California. These numbers are California specific.

COMMISSIONER MCALLISTER: Oh, they are. Okay.

MR. KONALA: Yes. These are California specific. These are not national numbers.

COMMISSIONER MCALLISTER: So NREL did both state specific and national?

MR. KONALA: They did a national average and I think they chose about 10 to 12 states.

COMMISSIONER MCALLISTER: Oh, great.

MR. KONALA: So I can forward the study if you're interested. But so just to answer your question, the other included permitting costs, inspection, overhead costs, customer acquisition and then also profit.

COMMISSIONER MCALLISTER: Okay. Great. Well, it would be kind of nice, in the context of the Title 24 Building Standards, to understand sort of what current costs are in that production build scenario, like what wouldn't apply. So maybe we can follow up on that.

MR. KONALA: Okay.

So finally, we're going to also consider the 2019 Title 24 Building Standards. But I will get into that --

COMMISSIONER MCALLISTER: That's a great segue for that. You're welcome.

MR. KONALA: I will get into that in the next slide a little bit.

So we will do an additional Achievable Photovoltaic Adoption Forecast Update. Just a quick recap of what it is. We did the AAPV for the last IEPR to account for PV system requirements for new homes, as specified in the 2019 Title 24 Standards. At the time those were for proposed standards. Now, they have been finalized. So in our baseline forecast we already assume that a certain percentage of new homes are going to adopt PV. So what the AAPV represents is it's the difference between PV adoptions due to the new standards, versus what we've assumed in the baseline forecast. So it's just the additional PV from the standards.

So since the standards have been finalized how do we want to tackle it? Is it still AAPV?

For the time being, for the 2018 Update we will keep AAPV around. It will remain separate from the Baseline Forecast. The main reason for this is to maintain consistency with the AAEE Forecast, which has not been finalized from my understanding. When both of them have been finalized then they will both be moved into the Baseline Forecast. And that will probably happen for the 2019 IEPR Forecast.

COMMISSIONER MCALLISTER: So I want to just endorse that approach, because number one we still have the Building Standards Commission. So we kind of don't want to count our chickens.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: And then defer to them, because they're the next step. So once they adopt, it'll be truly final. And then also the effective date of the new standards is January 1st of 2020, so it is kind of appropriate that we keep it sort of in the AAPV context until it's actually enforced.

MR. KONALA: Yeah. Finally, we do expect to revisit and update some of the assumptions we made in the 2017 AAPV. And the main things we are going to look at are the expected level of compliance that we assumed in the 2017 forecast, is it still relevant or accurate of what we expect today?

We also expect to revisit what the average PV system size for new homes will be. And we will be having discussions with other divisions within the Energy Commission to get feedback on this.

Finally, I want to wrap up the presentation by just going through the PV model that we use at the Energy Commission, as well as another model that is currently under consideration. So this is the model that we have today. The green and light blue squares represent some significant inputs into the model. Of course, we have historical statewide installed PV capacity. That is a significant input. And we also have housing counts from economic and demographic data. We also get forecasts of retail electricity prices that go into the forecast. And from the same data sets that we get installed capacity we also get system costs and performance data and some other PV related data that influence adoption.

So these data sets are disaggregated into residential sector, commercial sector and nonresidential, noncommercial sector. Each part of that model is run separately. And then once the models are run then we aggregate the total installed PV capacity statewide, and this is the forecast year-by-year. And once we have that, we use installed capacity to forecast the actual energy generated from these systems.

The residential and commercial models predict PV penetration based on calculated payback and bill savings. Payback I think was a low scenario and bill savings in the high scenario.

So we're also working with NREL. They have their own PV model that they recently released in the last year or two. This model is called the Distributed Generation Market Demand Model, or dGEN for short. The Energy Commission has contracted with NREL for NREL to develop a California specific version of this model. And that work is ongoing.

So just to summarize what dGEN is capable of, it simulates the potential adoption of distributed energy resources for the residential, commercial and industrial sectors. It's a bottom-up market penetration model. And it uses so called representative agents. An agent could represent an entire industry or there could be several agents within a sector. So that is something NREL is working on. It's capable of producing a more disaggregate geo-spatial forecast on the Energy Commission model is capable of. The Energy Commission's model currently can forecast at the climate zone level. We can do some information at the county level, but generally it runs at the climate zone level.

NREL's model is capable of running at the county level and at the zip code level. And also even more disaggregate than that if they wish. Of course there is a tradeoff. The more disaggregated the forecast, the longer it takes to run the model and the harder it is to actually find that data.

So while as NREL develops the California-specific model, and as we considered these levels of disaggregation, we're working with NREL staff to determine what is an appropriate level to run that model at and that work is on-going.

So that represents my presentation for today. So if you have any questions I'll be happy to answer them.

CHAIRMAN WEISENMILLER: That would be great.

And certainly, one thing we'll need to see with the NREL model is what the R squared is.

MR. KONALA: Okay.

CHAIRMAN WEISENMILLER: You know, I've seen some from them that was like 0.5, which obviously is not particularly great. But trying to really be pretty transparent about all of these. And also I was just trying to make sure, you know, one of the issues for you certainly is going to be how much data we can get for what's going on in 2018 to really drive things along. So do you have a sense of -- I know you see a lot of the data sources are more like annual, any chance we can get quarterly or half a year or something?

MR. KONALA: Data sets for installed capacity, a lot of the data sets are updated monthly, actually.

CHAIRMAN WEISENMILLER: That's great, that’s what we need.

MR. KONALA: So for installed data, we do have monthly. But there kind of has to be a true up as well at the end, because the most accurate data set is the IEPR 1.8 filings and those we get every two years.

CHAIRMAN WEISENMILLER: Right. Okay.

MR. KONALA: So we can use the monthly data, but at the end of every two years we'll have to go back and see if there's a shortfall and if so then go back and revise.

CHAIRMAN WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: Yeah, I was just going to comment. Maybe the project in terms of the localization of the forecast, it'd sort of be to work with NREL to figure out well what's the least, you know what's the smallest geographical unit that gives you a good enough set that you can have some confidence in it?

MR. KONALA: Yeah. An example of one of the challenges that we've encountered is if we want to do a forecast at the zip code level, demographic data is not really reliable at the zip code level. And Nancy could go into this a lot more than I can, but the Census Department for example, their zip codes don't align with the postal zip codes, because postal zip codes change over time whereas the census wants to keep them static. So since those don't align that does represent a challenge for forecasting at the zip code level. And we'd have to try to devise methodologies to get around that.

CHAIRMAN WEISENMILLER: Yeah. It seems like it'd be -- the Econ Demo is at county level, we can at least get to the county level. Whether we can go to the zip code level is probably a future step.

MR. KONALA: Yeah, at any rate, their model is capable of it. Whether we have the data or not is the challenge.

CHAIRMAN WEISENMILLER: That'd be the issue, I think is the underlying data as opposed to the model capability.

MR. KONALA: Yeah.

MR. RIDER: Yeah, I have a question. Could you go back to slide 3?

MR. KONALA: Okay.

MR. RIDER: So if I'm looking at this right, just quickly to check, yeah that was it right there. That's the forecast, the amount of behind-the-meter PV?

MR. KONALA: Yes.

MR. RIDER: So I'm just wondering how the belly of the duck is factored in here in some senses. I mean, are the CAISO entire load in spring is 22 gigawatts or so, give or take? And you're looking at a forecast that maybe adds that entire amount of load production, given that it'll be 2030. But to what extent do you factor in just the space or even the demand? Like does that feed back into the behind-the-meter PV forecast?

MR. KONALA: So we don't do this forecast at an hourly level. The hourly level forecast is post processed from this. The way anything like that would be input is in the retail rates that we use. So currently we do use time of use rates. But we did not use hourly time of use rates, so.

MR. RIDER: Well, I mean I guess the question would mean in the low electricity demand when it translates to hourly. Do you get pretty close to zero?

CHAIRMAN WEISENMILLER: You will. If you think about it, we hit like 8,000 this spring.

MR. RIDER: Right.

CHAIRMAN WEISENMILLER: As the total load, so as soon as you get to an additional 8,000 of roof top or solar of any sort you're going to be basically at zero.

MR. RIDER: Right.

CHAIRMAN WEISENMILLER: Or you're going below it and yeah, it's going to happen between now and 2030.

MR. RIDER: Okay. And then we're going just -- I guess the question is then (indiscernible) –to

CHAIRMAN WEISENMILLER: It is (indiscernible) --

MR. RIDER: Right, but then we're going to add another 15,000 behind-the-meter on top of that afterwards? That's what I'm wondering how it feeds back into the forecast, because obviously when that starts to happen and curtailment starts to happen, you know I think it would make sense to maybe -- I guess I'm suggesting that maybe it would make sense to start thinking about how that would affect the PV behind-the-meter forecast.

Because at that point, you're adding load into an already really intense situation and you're adding a lot more. I mean this forecast is like 10 gigawatts more on the low electricity demand, which is when you're at the lowest demand already. So I just -- I mean I don't know the real -- I guess I'm just questioning. I guess I'm just raising an issue perhaps with the Low Electricity Demand Forecast.

CHAIRMAN WEISENMILLER: So I think we probably need to identify when that point hits and try to figure out the policy option.

Other difficulty, back on the forecast model is we've always struggled with how do you deal with leases, in sort of a cost effective -- you know a lot of this is it cost effective or not. And once you get to the zero down, etcetera, how does that work? But obviously people are shifting more to purchases than leases. So anyway, there's some real -- I think the thing is to keep pushing the model development. But it'll be certainly interesting that when we cross zero.

MR. RIDER: Well, this number I see in 2030 may be the entire demand is met by behind-the-meter PV. And that's quite an impressive forecast. I mean like that's within the realm of possibility, I guess. That's news to me.

COMMISSIONER MCALLISTER: So I guess there is a lot of context here. I mean, we have a lot of behind-the-meter PV already. And the reason that net demand is as low as it is now is not just because you have a lot of utility scale that's forcing down the -- on the measurable grid, but you know a lot of the self-consumption in the middle of the day is why the midday net load curve is as low as it is.

And so, I think you also have to think about the future electrification, you know. The EV Forecast comes in, when are those going to get charged? So you're going to have an additional load as well. So I mean, I think all of this is malleable in both directions. And so I think that any effort to link say the PV Forecast with the ISO Forecast, I would. Yeah, it really begs all these other forecasts to be interlinked as well, right? So I think that's a brilliant broader conversation.

But absolutely, we've got to -- at the end of the day, the Building Standards and other policy, other programs are going to be in place. You know, the Building Standards are going to encourage onsite usage and storage. And so moving all this energy around during the course of the day and the month and the year, is going to end up being a central piece of that conversation to link all these different forecasts.

MR. KONALA: All right. Thank you.

MS. RAITT: Thank you, Sudhakar. So next, we're going to hear from Chris Kavalec on Hourly Demand Forecast. And he's also got a couple of extra slides that weren't in the original slide deck that we're going to include. But there's going to be some hard copies at the table and we will post it later today on the website.

MR. KAVALEC: Chris Kavalec again in the Energy Assessment Division. I wanted to touch on some methodological issues that have surfaced since we released our forecast back in February or it was adopted back in February. My presentation looks like this. I'm going to talk about a couple of issues related to hourly load modeling and how we will attempt to address these issues. And a couple of other methodological issues, everybody's favorite: weather normalization as well as Residential TOU.

First of all a little bit of background on the hourly load model. This slide shows the form of the model. You've probably seen this before. But anyway, what this is saying is that we are estimating hourly load, the ratio hour load to average annual hourly load as a function of weather variables and calendar affects. The weather variables we include are temperatures, dew point and cloud cover. And the combination of dew point and temperatures gets at and serves as a proxy for humidity.

Now a point I wanted to make here is the model itself, when you do a back cast it provides a very good fit. And this is not surprising when you're at the system level because your perturbations and shocks tend to cancel each other out at that level. So you have a nice smooth load shape, both actual and the estimated, as you see here.

They're very close.

So I'm showing Edison for some random days in 2009, because I had this available. So my point is the issue with hourly load model is not related to the model itself or the estimation. I think staff did an excellent job on that. It has to do with the weather normalization aspect, which I'll talk about in a minute.

All right, to implement this model we apply these ratios that were estimated through the regressions to annual forecast consumption load, which in this case means loads served by the utilities, plus the PV minus the EV load. And by doing it this way, we're accounting for economic and demographic growth and other changes that affect annual consumption. So even though those impacts are not explicitly in the hourly load model they are accounted for by the long-term forecast, which is applied to the hourly load model results.

We then adjust this hourly consumption load using EV charging profiles, PV generation profiles, residential TOU and hourly AAEE, Additional Achievable Energy Efficiency.

In terms of the hourly profiles, we're working on developing new charging profiles. That's one of the things we'll be talking about at the DAWG meeting on July 12th, this Thursday. Our PV generation profiles come from CSI simulation data. Residential TOUs developed in-house, in our Supply Office. And we developed AAEE 8760 profiles together with Navigant who does the CPUC potential studies for efficiency.

Okay. Weather normalized loads, so we did 119 different simulations using our regression results. Meaning we had 119 highest ratios, 119 second highest ratios, 119 third highest ratios. So to get a weather normalized hourly load, what we do is we take the median of the 119 highest ratios and the 119 simulations. That gives you the weather normalized hourly peak. We take the median of the 119 second highest ratios from our simulations. That gives you the weather normalized second highest load throughout the course of the year on-and-on all the way down to 8760.

In statistical terms, what we're doing is we're developing an expected value for each hour using the medians.

Okay. So all this part is fine here. We have a set of 8760-ranked ratios, load ratios. But then we need to assign the ratios to an actual day and hour. And the way that we -- you'll see this is in red here, meaning there's danger coming up. This is where the issue developed. To assign the ratios to an actual day and hour, we used an average weather year, in terms of cooling degree days and heating degree days. And that turned out to be -- in other words, we're looking at an individual year and looking at the degree days relative to historical averages for degree days. So those turned out to be 2009 for Edison and San Diego and 2012 for PG&E. So that's how we assign the actual days and hours of all our 8760 load ratios.

The reason we did it that way is you want to preserve the actual correlations among hours and days that you get in a real year. So that's why we used an actual year.

The problem with that is two issues were created in the way that we did this. Any peculiarities of a chosen average year, no year is going to be completely average throughout the year. So any peculiarities are going to get carried through to the forecast. So in our case, for using 2009 for Edison and San Diego, they had unusually low monthly peaks in May and June, in 2009. So that carried through to the forecast. So anything that happens peculiar to those two "average" years is going to carry through to the forecast and can create issues. So we ended up with seemingly low peaks for May and June, coming out of the hourly load model.

The other issue it creates is that when you're using two different average weather years, creating a misalignment for CAISO as a whole, because you're adding up the individual TAC loads to get a CAISO coincident load or peak. So using two different years this creates a misalignment, so when you add up the individual results from the TACs, you don't always get a good result for the CAISO coincident of the CAISO total.

So these are technical discussions that we've started having through JASC. And these will continue in our DAWG meeting on August 2nd. And basically, we need a method that preserves historical patterns across the years, while at the same time, it preserves correlation among the days and hours. So that's our task, to find a way to do that.

Another issue or something that's contributing to this misalignment of CAISO, although I think this is a minor impact, compared to what I just described. We estimated three models separately, one for each TAC: PG&E, Edison and San Diego, because that's the way we work. We project our planning areas independently. That's the way we've always done it. However, we know that there are correlations that exist among the TACs in CAISO and this is not explicitly accounted for when we estimated the TAC models independently.

So there's an easy solution to this. And that is you can use statistical techniques and estimate on a pooled cross-section time series model, so you're doing an estimation for all three TACs at the same time. And this will allow you to account for the correlation among the TACs in your coefficient results.

Another issue that came up during the 2017 IEPR process is that Edison voiced some concerns about the magnitude of their peak shifts compared to PG&E. And what we pointed out to them is that in the case of Edison peak shifts, and for those not familiar that means the shifting hour of the utility peak brought about by PV and other demand modifiers. So what we pointed out to Edison was that their loads seem to fall more quickly in the later afternoon and evening, versus PG&E. So they're going to have less of a peak shift impact.

Their response was that overall this may be true, but in more recent years, they think that loads are pushing out later into the afternoon and evening. So if we base our results on more recent years we're going to find more of a peak shift.

So we looked at this. And there is some evidence for Edison's assertion. It's hard to see in this too-busy graph, but the early years tend to peak earlier and then decline more in the later afternoon and evening, compared to the later years.

So an alternative here would be to re-estimate the model, leaving out the earlier years. And that's also what we'll talk about in the DAWG meeting on August 2nd. So the question is always how many years are you going to eliminate, because there's a tradeoff between -- you want up-to-date information, but you always want to examine as many temperature history years as possible. So under those, that's under discussion.

Okay. Weather normalization became an issue in recent months after the 2017 Forecast. As a reminder, weather normalized peaks for the last historical year serve as the starting points for our peak forecasts. Recent forecasts have shown a bouncing around of starting points, as stakeholders have pointed out to us, and those peak forecasts. So our starting points seem to be moving up and down a lot in the last three forecasts, which means our peak forecasts are moving up and down. And this is not good for resource planning.

So this came up during a JASC discussion and we agreed to look into it. And what we found was that what happens is that the relationship between temperature and load can fundamentally change from year to year. So if it's 75 degrees one year, the load will be X. The next year, it might be something higher than X. Then the year after that, it might be something lower than X. So not just one temperature, but systematical across the temperatures, you can see a different relationship. So that's causing this jumping up and down.

Another source was three forecasts ago, in our simulations, when we do our weather normalization estimates, we went from 50 or 60 years down to 30 years, to choose. So we created a distribution with 30 entries. And the median of that distribution becomes the weather normalized peak. So when you're using 30 years instead of 50 or 60, the median is going to be bouncing around a lot more than it would in the longer time period, so that's contributing to this too.

So we talked about potential methods to address this variability. This is something we want to eliminate. So we talked about possibilities, like using more historical years to stabilize the weather normalized peak. Or there are other statistical techniques like Bayesian methods where you specify a prior for your estimate that comes from the previous years' weather normalized peak. So that would tend to stabilize the weather normalized peaks from year to year. And again, so that's another issue coming up for August 2nd, how best to stabilize and prevent this jumping around of our peak forecasts.

We also discovered since the 2017 forecast was released that a residential TOU was not aligned properly with the resulting loads. In other words, we have high TOU effects with lower load and low TOU effects when there's higher load, which is not logical. Okay. So that came about because of coordination issues between our Supply Office and the Demand Office. So in other words, it's my fault. So we will endeavor to correct this, so these TOU impacts line up correctly.

And while we're doing this, we also have the opportunity to update IOU TOU profiles, because there is needed data coming up from the current default pilots, so we will have data coming for the summer, available in the fall. And we can use that, so we can revise or update participation rates and opt out rates and other important variables.

I had a couple of more slides here and this issue is related to the hourly load model. Every year, for the past 10 years or so, we provide a sort of off the books product for the California ISO, for their annual WECC filings. What we do is provide them our estimates of monthly consumption, monthly peaks by TAC area and monthly efficiency impacts for each year based on the IEPR Forecast. And as we always say, this is not an official CEC product, but it's something that we're doing to help you with your WECC filing.

So this came up, we did our WECC filing or we provided the data for the WECC filing just after we adopted the forecast. And this became an issue because there were certain questions about the monthly RA numbers that seemed a little bit low for 2018 especially in September. So an alternative was proposed, use the Monthly Peaks Forecast derived from the IEPR and provided to CAISO for the WECC filing as I just described.

So what I did here in doing this WECC filing was I used the hourly load model results, which as I mentioned before do not always provide reliable results for total CAISO coincident peaks, because of the issues I mentioned. So what I did was I scaled the hourly load model results so that the CAISO coincident peaks would match the IEPR forecast basis. So I did a true-up of the hourly load model results in this WECC filing.

The question was raised, "Well, can we use this WECC filing instead of the RA forecast, which seems a little bit low for September?" You'll see here the difference. The red is the WECC filing I put together, using the hourly load model results. And the blue is the RA Forecast and there's a difference of around 1,250 megawatts in September. And what is going to be the result for RA, I don't know yet, but it's still under discussion.

But I wanted to present this sort of for the record, because CAISO is using this, my WECC Monthly Forecast in their flexibility analysis. And this was not specifically adopted when we adopted the forecast, so I'm presenting it here. So it's now on the record.

Okay. So that was my presentation. Questions, comments?

CHAIRMAN WEISENMILLER: Yeah, no. Thanks Chris. This is really helpful. I think that -- I assume that some of the hourly forecasts, peak forecasts basically should equal sales for the owner, so as long as you've got different ensembles of years across these entities there's got to be some issues there.

I guess the question on the thing that really got my attention was you mentioned how going across different years, having the same temperature can have different affects. And how we're concerned about trying to get a more stable forecast. At the same time, we have to have both stability and accuracy.

MR. KAVALEC: That's right.

CHAIRMAN WEISENMILLER: And this sort of bouncing round. You would anticipate -- sort of like if you look I guess UCLA was 111 this weekend? And presumably, now that people are getting power back, they're probably more -- anyway regardless of today's temperature in Los Angeles, the forecast lows are probably going to be higher than you would anticipate, just from that rebound. So I don't know if that's part of what we're trying to deal with is the linkage between the sort of the day before or the day before that on a particular temperature.

But it seems like one is we could try to get the expert panel to focus in on is what's going on. And as I said if the relationship between a given temperature and a peak bounces around, that's going to have real problems. It will present real problems for us either in terms of stability and/or accuracy, or both.

MR. KAVALEC: Yeah. So one possibility, which you just mentioned is that it's a function of when the hot days occur. When and if you have heat storms. So something like that, I would think would be corrected for. And so entering temperatures in different ways and accounting for when the temperatures are happening could help achieve more stability. But on the other hand it may be something more fundamental going on that's sort of beyond the scope of a relatively simple weather normalization process like this. So that would mean developing a much more complicated model and/or developing a method or just acknowledging that it's happening and saying "Well, we can't keep moving our peak forecast up and down just because this is happening. We want a stable forecast. And we want to stabilize the starting point and account for the fact that this changing temperature load relationship, we'll attempt to account for that using scenarios."

CHAIRMAN WEISENMILLER: Well, we could be more explicit on the range of uncertainty.

MR. KAVALEC: Right.

COMMISSIONER MCALLISTER: Yeah, that's actually -- I was going to go there.

I guess I'm kind of wondering about the relationship between sort of the modeling issues that you're talking about and just the fact that weather itself is becoming more variable and creating sort of a broader distribution, even if you've got this sort of a median problem and trying to figure out what the median is for purposes of the forecast. And then you've got the variability around that, going forward, in terms of your year 1, 2, year 5 or whatever. So I guess how do those two things play together? And does if -- well, first of all is there? Do you have evidence of sort of increasing variability of the weather in ways that affects the forecast? And if so, sort of how does it relate to these analytical issues you're talking about?

MR. KAVALEC: Yeah so when we developed this model and we weather normalize, we're basing things on historical weather. But, as you're saying we may be entering an era, because of climate change, of more variability. So because of that possibility we're talking to Scripps about developing hourly temperatures. Right now, they provide us scenarios for daily temperatures that are meant to reflect different climate change scenarios. And so we're talking to them about also doing an hourly forecast that incorporates climate change, to try and get at that. Did that answer your question?

COMMISSIONER MCALLISTER: Yeah, I think so. I think it really goes to what the Chair just said about figuring out ways to express the uncertainty, right? So we can now pick a point and you know a proper median and sort of do that year-to-year and sort of do that the best we can. But we're also going to have more uncertainty just layered --

MR. KAVALEC: That's right.

COMMISSIONER MCALLISTER: -- over wherever whatever it is, wherever we land on that base forecast, right? So capturing that somehow.

MR. KAVALEC: Okay. Thank you.

MS. RAITT: Thanks Chris.

So next we have an update on the Community Choice Aggregation from Miguel Cerrutti and Chris Kavalec.

MR. CERRUTTI: Hi. Good morning, I'm Miguel, the presentation about the CCAs on some other issues that we have beginning this year and hopefully won't have next year.

This is a map I took from the California CCA.

It's little bit behind. There are three specific CCAs that are yellow. Right now, they are already green. They are serving loads this year. One is San Joaquin, the other one is King City and the other one is L.A. But this is the actual map. I am guessing there might be more in the next year, but I'll go over that a little bit later.

The CCA data I am talking about is the data that goes into the IEPR form, once delivery is to the end user by agency. Almost 100 percent of the CCA data comes from QFER. That is the Quarterly Fuel Energy Report that is the history.

Basically we need the monthly data each quarter, at least to the four quarters, because in 2018 we might have some issues with the CCAs that started later this year. We won't have data until November or January next year, so it would be difficult to include those.

Sometimes when we don't have data from QFER I go to Resource Adequacy in order to get the Year Ahead Forecast. They should meet by role to the PUC and to us the Peak and the Energy Forecast for 2019. And so we compare the numbers and we do a low factor. However, there is a gap between what we get from the IOUs and the CCAs, so we have to do a possibility allocation in order to make those numbers really close.

And sometimes when we are still running out of data, we go to the IEPR data. However that is limited to the LSEs with more than 200 megawatts, so there are many CCAs that are really below 200. So we miss that data.

This is the (indiscernible) list that we are using for RA, the existing CCAs. The name for the CCAs, the date where they come in service, when they submitted the QFER data and where they are located. And most of the CCAs we already have enough data for 2018, however there are some that they started later like one is King City community starting July 18. Hopefully we'll get data by August. However, there is another one that I have a question mark is there's a Community Energy starting August 2018. So hopefully we will get some data by November or early next year. Also, we got Solana Energy Alliance that's in San Diego. Already started in June 2018 and so we don't know if we will get data from QFER.

So in terms of the short-term data that we get from the city as we are there, the issue is when we are trying to get data in the long-term. What happens in the next three or four years if we don't get any data from the RA.

So in order to update this right now we have all the existing CCA serving customers in 2018. We already started the process for the year ahead, for RA. So we already have all the data from the CCAs that are going to be serving in 2019. So we are kind of ready for the 2019. We already finished that process.

The only issue that we do have sometimes is when the timing of the phases, some of the CCAs don't count serving the full load, or sorry, all the customers in one month. Sometimes they start with 10 percent of the residential. Next month, another 20. The third month, another 40. So that's a timing on phases, sometimes we do have promise, but for 2019 we do believe we have all what we need.

Right now, in July 10th of this year, we don't have any information on new CCAs coming in 2019. There are many parties that would like to participate, but they have not applied to the PUC for a certification. So right now, we don't know any information. Sorry, we don't know if there might be new CCAs in 2020, '21, '22 or whatever. We do not have, so we know there are several entities that are interested, but they are behind in the process.

So however, the PUC has a new regulation. And so these new CCAs have to fully comply with the rules and time line. So any new CCAs out there would like to start doing 2020, they have by 1st January of 2019. They have to provide the information and they have to be implemented. By March and April, they are supposed to submit not only historical data, but also the forecast peak on energy. So by that time, we should know which new CCAs will start serving customers. And that will hopefully mitigate the impact for the RA, for the multi-year RA also for the LTPP and the IRP. That's it.

CHAIRMAN WEISENMILLER: Please, will you take a couple of questions?

MR. CERRUTTI: Sure.

CHAIRMAN WEISENMILLER: One is a history good news, looking further out as to when we keep doing the annual updates on the CCAs, which are pretty volatile. But the one thing that was pretty clear at the En Banc, is that a CCA might file with the PUC and say we're going to set up a CCA, we're going to serve say like 10 gigawatts. And then they get into the RA filing. And they say, "Okay. For the first year we're only going to serve a fraction of that."

And so basically trying to reconcile what the actual numbers are. And again, it's not unusual for the Business Plan to say "be all," although for example I think the Alameda one will be all residential and commercial customers in state and in local government facilities. But at this point, they're only hitting local government facilities. And say a year from now, they might go into residential or other pieces. So one of the challenges is not only knowing that say there's a CCA in a given area, this is their plan overall for the market. But then what are they actually doing year-by-year?

MR. CERRUTTI: Right now, when they submit data for 2019 and for any reason they expand the load, they will modify in the market basis load migration. That's --

CHAIRMAN WEISENMILLER: This isn't load migration. Simply they're not even going after certain market segments as they go through. Now again they might say, "Okay, we're going to go after residential and have 10 percent migrate back." But this is they just haven't flipped the switch on the residential part of their market.

MR. CERRUTTI: Yeah, It is difficult to get really very good data, especially in the long-term, or they are going to expand. It's difficult.

CHAIRMAN WEISENMILLER: Yeah, I know. I mean long-term we have to pick up year-by-year. And the challenge is going to be using QFER or something to really get a good number for this year, realizing that each year we're going to continue to stay on top of that. But that it's really important to get this year's numbers right, which gets to you know again, QFER or trying to -- or the RA filings at the PUC. Although as President Picker pointed out, there's a lot of -- these are 11 so far, which basically have said, "We're going for an exemption on the RA process, because we're in the process of setup, so we're just not going try to comply with PUC's regulations."

MR. CERRUTTI: But this year, January, February 2018, when we were doing that the IOUs provided us some of the information for the long-term forecast for energy. So that was really very, very helpful.

CHAIRMAN WEISENMILLER: Right. But again, as you look at the longer term, we're going to have true that for every year. So that -- whether the IOUs are optimistic or pessimistic, or whether the CCAs are optimistic.

MR. CERRUTTI: Well, that's why in the RA when we combine the IOU data, about the new CCAs and the CCA numbers, they don't match. And so we need to do an adjustment there.

CHAIRMAN WEISENMILLER: Yeah.

MR. CERRUTTI: So we assume that we never match.

CHAIRMAN WEISENMILLER: Or maybe ten years from now, but not now.

MR. CERRUTTI: Yeah, that could be.

COMMISSIONER MCALLISTER: When those were all getting developed I guess another thing that was clear from the En Banc was that the CCAs really have no concept of the decoupling and sort of how they approach energy efficiency. And again, lots of uncertainty when push comes to shove and distribution grids are stressed, what are they going to do? Are they going to push efficiency or not? And they don't really have a financial incentive to do so. So the uncertainty around the AAEE going forward I think is another consequence of the CCAs. So we need to pay attention too.

MR. CERRUTTI: Yeah.

COMMISSIONER MCALLISTER: Okay. Thanks.

MR. KAVALEC: Chris Kavalec, again. This is a -- what I'm going to talk about now briefly is a remaining issue that was brought up at the Business Meeting, when we had our forecast adopted. And at that time Silicon Valley Power requested that we reexamine their forecast to account for an expected significant expansion of data centers in the Santa Clara area, which use a lot of load. So this represents a significant increase for SVP as a whole.

Well, it was late in the process and we said that we will reexamine your forecast for the Forecast Update later this year. So that's what we're doing. Santa Clara is a hub for data centers. They currently have 32. And as I said, they expect significant addition/expansion in the next few years, which is not accounted explicitly in our forecast. So they provided us a lot of information, specs for addition/expansion by the each entity, load factors, other information, total load.

And this all seemed pretty reasonable. Everything was backed up. The numbers were backed up. So what I've done here is to show what impact adding in that incremental load for data centers, going out into the future looks like in terms of an overall increase for SVP's load. And I should mention almost all of the incremental load is coming from three bigger entities: Vantage, CoreSite and Digital Realty.

So what I did here was to show using SVP's numbers the forecast from 2017, the mid baseline combined with mid AAEE. That's in the blue and then the additional load, expected to be created by data centers in the next few years. SVP, in their projections, went out to 2027. So I just held 2027 to 2030 constant in terms of the increment. So a little bit over 1,000 gigawatt hours additional load, by the end of the forecast period.

Peak, not so much, a relative increase given a pretty high load factor, 130 megawatts of additional load by the end of the forecast period at peak.

So some next steps. The first thing we have to do is within our forecast, on a commercial side we forecast individually by building type. So within our forecast, implicit is some growth coming from data centers, corresponding to the building type that data centers fit into, which I believe is the commercial miscellaneous building sector. So there's already some growth there, in the forecast. So that has to be netted out and prorated for SVP and subtracted from the numbers I've shown here. I don't think it'll be a lot, but it needs to be accounted for.

We will then check back with Silicon Valley for comments or, importantly any updates, if there are any.

And we also have another -- we have an issue with significant weatherized peaks in the last historical year with Silicon Valley that we're going to need to reconcile for the Forecast Update.

Okay. So that's where we are on that. I believe now we have additional presentations for CCAs coming from PG&E and Southern California Edison. So I guess we'll start with PG&E. Ali, if you're here?

MR. MOAZED: Okay. Thanks, Chris. And thank you Commissioners for the opportunity to present PG&E's update on our CCA Forecast. My name's Ali Moazed. I'm the Manager of the Resource Forecasting Team at Pacific Gas and Electric. It's a newly founded team that focuses on long-term forecasts for customer energy services and load modifying resources, all the DERs that we're talking about today and that are included in the IEPR Forecast.

So today, I'll be providing an update on our CCA forecast. And it reflects our March 2018 Update that was used as a basis for our ARRA filing. But before I get into that, I would also like to just extend a thank you to Chris and Miguel for working closely with us in the production of the Final CED Forecast. We started off with a quite a gap. You'll see that in the presentation. And we closed that gap and shared a lot of information and created some informal channels to share that information that you've been talking about that's critical to the long-term forecast. So we look forward to continuing that collaboration, with a particular focus on long-term forecasting.

So as the Commissioners mentioned, at the beginning of the meeting, the foundation of long-term planning is having a good sense of the forecast, what the drivers of the forecast are and what the key sources of uncertainty are. So the CED has been adopted by the IRP or by the CPUC as part of the IRP and informs renewable procurement as well as allocates responsibility for attaining state level policy objectives. And we also use it to inform our reliability procurement.

So there's been within the CCA realm there's been rapid expansion recently that's given more importance to this element of the near-term and long-term forecast. So we've moved essentially, from a place where in 2016 we had four CCAs serving approximately 5 percent of PG&E's system load to an expectation of, by the end of 2019, having 12 CCAs in place serving 42 percent of the PG&E system load.

So the magnitude and the speed of the change is -- it feels unprecedented.

And the map here on the left is kind of our internal version of what Miguel shared which is the CalCCA map. This is our internal perspective on that with the purple reflecting existing CCAs and then various degrees of CCA activity in the other colors. So you can see some of the inland areas have not moved much, are not classified here as having taken on CCA formation activities at this point.

So I'm going to break this up into a snapshot from our near-term forecast and a snapshot from our long-term forecast, 2019 to 2030. This chart shows four different versions of the forecast for 2019. Starting from the left there's the draft CED from January, 2108. The final CED from February of 2018. Pacific Gas and Electric's expected case, which is updated in 2018, March of 2018, and used in our ARRA filing.

This is the IRP adjusted, which in the IRP process three CCAs submitted amended forecasts. So what we did is substitute those forecasts into the CED and use that for the IRP.

So the consensus estimate, the good news here is that we closed the gap between the January 2018 and the February final CED. There's a consensus estimate is somewhere around 40 percent of load will be served within our service territory by CCAs by the end of 2018.

So we have strong alignment in the near-term forecast, that's primarily driven by as Miguel mentioned CPUC Resolution 4907, which requires a year ahead filing by January 1st. This year the deadline was extended to March and so that's part of the reason that we were receiving the information from the CCAs. So we had to work with Miguel and the CEC team to make sure that we had a channel to share that information, to update their forecast.

But in the future, that information and those forecasts from the CCA should be available. So we have relative certainty with respect to a year ahead view of the CCA forecast.

There's another element of the ARRA process, the meet and confer process, where we're afforded the opportunity to meet with the CCAs, review their forecasts, match them to our own internal forecasts, assess their assumptions and their inputs. And then decide whether we're going to adopt those forecasts as our own, or we're going to put forward our own forecasts.

I think in the last cycle, in 2018, we ended up using 9 out of 11 forecasts that were submitted by CCAs. So generally aligned with the CCAs.

COMMISSIONER MCALLISTER: How much evaluation of those forecasts do you do? I mean, do you give them a sniff test before you sort of decide to adopt them?

MR. MOAZED: Oh, yeah. So we do a side-by-side comparison, you know, look at the key input assumptions, opt-out rates for instance, load growth rates, classification of loads by segment and depending on what segment they're serving we do a compare and contrast. And then make the decision about whether to adopt our own or whether they're close enough that we would just adopt the CCAs.

COMMISSIONER MCALLISTER: Either way, they're going to be similar though right? I mean, it sounds like you're putting them through their paces.

MR. MOAZED: Yeah, and there have been instances where we've decided to adopt our own, because we didn't agree with an opt out rate or load growth rate or something like that.

COMMISSIONER MCALLISTER: Yeah. Okay, thanks.

MR. MOAZED: Yeah. So the third element here that I've mentioned before, as a driving alignment, is a good collaboration with the CEC staff on developing the forecast.

So a little bit of a different story, in terms of the long-term, as kind of building on some of the discussion in Miguel's presentation, there is a considerably more uncertainty in the long-term as with any forecast. The kind of uncertainty the further out you are in the forecast horizon, the more uncertainty there is.

So this is the same four forecast vintages. I have the draft CED, final CED, PG&E's currently adopted forecast and the IRP adjusted. And you can see that there's about a 40 percent difference between PG&E's expected case and the final CED that was adopted here.

There are a few drives for the divergence. One is the just there's high level inherent uncertainty. So in terms of new CCAs there's no obligation to file beyond one year. So we have certainty within the one year window, relative certainty. But any CCA that's forming beyond 2020, at this point we have to look to market information. So what activities are currently underway in terms of CCA formation at the local government entity? So we'll work closely with our government relations folks and people on the ground to try to understand what is going on in the market there.

With existing CCAs, we've had cases where we've received implementation plans. Those implementation plans were either altered significantly or not followed. So even if we do have a plan, there's no binding requirement to follow that plan at this point.

And then I'll say one other factor that's contributing to the uncertainty is just the speed with which CCAs are now forming. And so it used to be you'd have kind of a longer window. When you'd start hearing something, you could build that into your forecast. And now it can materialize much quicker due to some efficiencies in the CCA process.

So the second driver of uncertainty, and I think one that we can work with CEC on closing, is just the embedded assumptions and the differences in the forecasting methodology. So the CEC model assumes that CCA growth is constrained by load growth and that new CCAs are not accounted for in this model. So any change between 2019 and 2030 is driven -- my understanding is exclusively by -- changes to the load of the existing CCAs in 2019.

So the IOU models, SCE's model and PG&E's model, although they're different methodologically, both account for continued expansion of the CCA model. Now, there's a lot of uncertainty about what that expansion looks like. And our forecasts are probably wrong, but they do account for continued growth and a continuation of the trend that we've seen in terms of new CCA formation.

So while we acknowledge that it's challenging to account for and quantify the uncertainty. And we do think it's a reasonable assumption to assume that CCAs will continue to continue to form. And for long-term planning purposes we think it's best to try to capture some of that uncertainty in the forecast.

Just as a note, Energy Division at the CPUC developed a paper in 2017. And I think they identified by the mid-2020s that up to 85 percent of an IOU load could be departing, whether it's departing to DA, to CCAs or distributed generation and so even if they're looking at extreme bookend scenarios for planning purposes. And so part of our recommendation here is that we work with CEC to see how we can quantify the uncertainty in this market in the long-term, given the lack of binding notification requirements for CCS.

So that concludes my presentation. Do you have any questions?

COMMISSIONER MCALLISTER: I have one question. It's not really related to CCAs as much, but sort of PG&E's forecasting work that you do internally, either formally or informally, with us. How much scenario work are you doing around electrification and the EV electrification, which I'm sure everybody's doing work on, but just the electrification of end uses? And that's something we're going to have to focus on next year, in the full IEPR. In the full forecast, but I want to kind of get people thinking about that.

MR. MOAZED: Yeah. So we have a -- we do a

Stationary Electrification Forecast and we have a model. And the model is broken up into retrofit and new construction modules. And it's a very nascent market, at this point. We don't have a lot of historic data to inform an econometric model. Like we actually have done that, but we don't believe -- we think that it's overbuilt for the current understanding of the market. So we're modifying this year to move actually backwards from using that econometric model to something that's more policy oriented. So kind of a scenario based modeling, based on policy.

COMMISSIONER MCALLISTER: Yeah, I mean I think that makes sense. There is going to be a policy discussion soon. It's already started, really. And so depending on what program scenarios, what program environments evolve that's going to have a big influence on that. And Title 24 is already engaged with electrification in the new construction. And we're going to have to -- depending on what legislation passes and everything. But in any case with the EE doubling and with the existing Building Efficiency Action Plan we're going to have to talk about it as well. And that's going to be happening kind of in earnest next year.

So anyway, we want to coordinate with you guys on all that and the other IOUs.

MR. MOAZED: Great. I'm happy to do that. Okay.

MR. CALDWELL: I just have a quick clarifying question for you. Thank you for your presentation.

When you talk about projecting expansion of CCAs are you talking more about increasing load in the existing CCAs or is that more towards the formation of new CCAs moving forward? I'm sure it's some combination of both.

MR. MOAZED: Yeah. So there are maybe three elements to that. One is load growth of the existing customers of CCAs. The second is expansion of the existing CCAS to incorporate new customers and then the third is the formation of new CCAs. So talking about more the latter two of those and less focused on the load growth within the existing population of CCA customers.

CHAIRMAN WEISENMILLER: So, as you struggle with the question of the implementation filings and then the actual implementation, what -- I mean in terms of PG&E's perspective what are your incentives on how to deal with the uncertainty there? Do you tend to go high, low, I mean how do you? Obviously, you get a more experience over time on the divergence between the plans and the actual realities.

MR. MOAZED: Yeah, I can't say that we favor going high or low at this point. What we try to do is work with the CCAs through the meet and confer process to really get a sense of where they're going to land in the near term.

CHAIRMAN WEISENMILLER: Yeah. I mean, it's one of the things we struggled with or at least I struggled with at the En Banc was that presumably the CCAs have a forecast of what's going to happen. But as you indicate honestly, bound by that, and as the PUC goes into issues like RA or something in doing the allocations between the IOUs and the CCAs, again the consequences of either under or overestimating that split is always a challenge. In terms of the cost allocation really of the applied risk, reliability risk assessment.

MR. MOAZED: I agree.

CHAIRMAN WEISENMILLER: Okay. Thank you.

MR. MOAZED: Thank you.

MS. RAITT: Thanks, so next is Eduardo Martinez from Southern California Edison joining us from WebEx.

MR. MARTINEZ: Good afternoon.

MS. RAITT: Hi, good we can hear you. Let me get your presentation.

MR. MARTINEZ: Great. Thanks.

MS. RAITT: Okay. Go ahead and just let me know.

MR. MARTINEZ: Thank you. Luckily Russ, (phonetic) and Miguel, Chris and Ali have talked a lot about the things that I was going to present, so I don't really have to go into too much detail. So I'm going to focus mainly on how this applies to SoCal Edison. Like Ali, I want to thank (indiscernible) they've given us and also Chris's continued work on weather normalization.

Can we go on to the first slide? So with everything that was covered today and like the folks talked about the impact of the RA ruling, especially for (indiscernible) change in terms of forecasting, near-term and also the long-term outlook. The next slide?

The Resolution E-4907, which came out earlier deals a little bit in terms of the IOUs, how we forecast in load. In particular how this impacted Edison here to kind of give us a clear idea as to what to expect. So for by the end of the 2019 we expect to have as active Lancaster, which (indiscernible) 2015; Apple Valley; Pico Rivera, which started in term 2017; Clean Power Alliance, that's the latest name for the Los Angeles County entity, which has also branched to Ventura County; San Jacinto and Rancho Mirage became active in desert cities, which again starts in August of this year.

One footnote, actually two footnotes, Riverside County was included in the language of the resolution, however they opted not to begin CCA service in 2019. So when we did our (indiscernible) filing we're not including Riverside County. We're not assuming Riverside as being active of the CCA for 2019.

Then for Clean Power Alliance there were five phases. Phases 1 and 2 are active. Phase 1 was the filing of (indiscernible) municipal account, which was mentioned earlier. Phase 2 started with residential accounts in unincorporated L.A. County and two incorporated cities: Rolling Hills (indiscernible) and South Pasadena. The rest of the cities that have joined on to CPA's joint power authority, they're expected to start in January of next year in three phases. And this is CPA's RA filing they did for next year.

Here's our next year, a little bit different than how PCIA (phonetic) had done it and how they did it for PG&E. Here we're showing you the exact incorporated cities or unincorporated areas. A sort of caution with this, a lot of these unincorporated areas, especially Northern L.A. County and Ventura County, there's not a lot of population. So it is a big mass, but most of the populated areas for the county, especially for L.A., are going to fall out of Edison territory because we don't cover L.A. County obviously. Or it's going to be incorporated to either have it joined.

And actually Ventura County is the only city that (indiscernible) territory where we actually have 100 percent coverage of I think the county. Next slide?

So something, and this may be specific to Edison, but when we do a forecast we had previously a three-point part here. We've actually expanded now to four points, so we only assume and (indiscernible) going out a CCA departing load if four conditions are met. The first one is they do a binding notice of intent. Only Lancaster is the only CCA to do that. They do an initial RA filing, which the other ones to date have done, so for instance Pico Rivera, Apple Valley CPA starts a CPA service. So for next year obviously Lancaster already exists, so they're now covered by that. And now because of the new filing if a city going forward is going to be doing an RA filing for the next year by the April filing deadline we want to include them. So there's my little abbreviation there showing that it's listed as a new (indiscernible) forecasting methodology starting for 2019.

And actually, can we jump here to the first backup slide? There we go. Oh, go back to the beginning, one more.

So here's the diagram. So basically we're expecting roughly 40 entities and by entities I mean either incorporated city or unincorporated city. And there's more complexity here, because of phase outs or the phases. Sometimes it's just municipal load only, sometimes it's RASS and it's sometimes it's non-RASS. So for us, even though we did get certainty from the CPUC filing there's still a little bit of a complexity that we have to do here. And that's we have to get load profiles for RASS, a load profile for non-RASS down to the city level.

So again we've learned a lot in sort of expanding our methodology to get a tackle on the challenge here.

Now we can go back again. Okay. Actually go one more to the Long-Term Outlook. I apologize I don't have our current load right now for CCA, but if the Commissioners do want that I'll (indiscernible) give you the load and sort of (indiscernible) that we're serving as of the end of June. It just wasn't (indiscernible) wanted that information.

But for the long-term outlook what we did here is that we took advantage of the last 2013 IEPR filing, the recently submitted IRP Forecast that the CPA submitted and our own internal forecast for 2030 just to give like an idea of what range.

Well, first of all you see that they've increased from the 2017 IEPR, 2018 IRP. This is sort of the stress, this is sort of the fluctuations. That the CCA outlook has bene in flux a year (indiscernible) scenario and take a look at. But also for our forecast here we had that light blue line, which is the Monte Carlo simulation, which is similar to what PG&E does.

So for the first years of the forecast, so that goes back to the four-point role we have definitions or criteria that need to be met. But after the (indiscernible) for mid-term to long-term procurement purposes we feel that it is justified for us to do a Monte Carlo simulation.

So we do the Monte Carlo simulation and through our Customer Service Division they track CCA activity, so anything from a city requesting data on their load (indiscernible) they do a municipal ordinance, they file an implementation plan that gives them a probability. The idea is the further up you get to the implementation plan, it's not going to be 100 percent, but it does give you more probability that you may become a CCA in the future.

Then we run a Monte Carlo simulation based on that with some other factors, based on the billing of history and whether a city belongs in an existing CCA aggregation. Say for instance you're an incorporated city for L.A. County and you're going to CCA, yes you may get a small little piece in your probability. Based on that we run a 10,000 simulation, Monte Carlo simulation and come out with results there.

The next thing you're going to be wondering is that our forecast is lower outside of that blue line. The main driver for that is that when we do our retail forecast we actually see (indiscernible) declining retail load in what we call our mid-point or forecast going to 2030. A lot of that is because of DER penetration efficiency gains.

I've shared this forecast with the CCAs. I haven't really gone into (indiscernible) but my suspicion is that they're probably also doing that reduction in retail growth the same way that they do. But that might be an area for us to look into and the future it could just be (indiscernible) longer range (indiscernible) --

COMMISSIONER MCALLISTER: I'm going to butt in -- I'm going to butt in just for --

MR. MARTINEZ: But we are accounting for all of the things that we do that our retail sales will decline (indiscernible) --

COMMISSIONER MCALLISTER: I'm going to butt in just for a second.

MS. RAITT: Sorry.

MR. MARTINEZ: -- (indiscernible) our forecast.

COMMISSIONER MCALLISTER: Oh, can he not hear me? Hey, I'm just going to butt in just for a second, it's Commissioner McAllister. You mentioned more detailed information for the CCAs individually and I want to encourage you to submit that.

MR. MARTINEZ: Okay.

COMMISSIONER MCALLISTER: We would like to see that.

MR. MARTINEZ: Sure. Like I said I could probably do what's active as of the end of June 2018 or the beginning of July. That's probably the best way to do it, but probably I'll work with my Customer Service Division and we'll get that information to you.

COMMISSIONER MCALLISTER: That will be great, thanks a lot.

MR. MARTINEZ: Will you want load and service accounts?

COMMISSIONER MCALLISTER: I think as much detail as you can provide would be great.

MR. MARTINEZ: Okay. Yes, I will follow up on that.

COMMISSIONER MCALLISTER: Great, thank you.

MR. MARTINEZ: Next slide, so uncertainty especially for a long-term forecast, like I mentioned before especially when you do the Monte Carlo simulation we have several entities that have started considering CCA. But (indiscernible) CPUC, but they haven't been approved, but getting really back to that four-point picture and also the CPUC's ruling for 2019. So we expect them to become -- a good chance that they will become CCA departing loads in the future, but because of the uncertainty out in the future we're not sure exactly when. So that's why we chose the Monte Carlo simulation.

Also PCIA reform made also the consideration for the CCAs for adopting in the future, so (indiscernible) awaiting to see what that decision's going to be. Then we can sort of flesh out what the impact is going to be, so again the bottom line of this is that we show the Monte Carlo simulation is appropriate for us. Especially in terms of mid-term to long-term procurement, to try to model that as much as possible using that type of scenario. And do I have one more slide? It's back up right there.

Yeah, like I said the folks at CEC and PG&E, they touched upon a lot of what I was going to talk about, so I don't have to go too much into detail. But I'd more than happy to answer any questions.

CHAIRMAN WEISENMILLER: Yeah, hi so this is Bob Weisenmiller. The one question I would have is there is -- you know, you have CCAs and you also have ESPs.

MR. MARTINEZ: Oh, I think you may have muted me out.

MS. RAITT: Oh, I'm sorry. I thought you were muted. Go ahead, sorry.

CHAIRMAN WEISENMILLER: So yeah, this is Bob Weisenmiller. So you have CCAs and you also have ESPs and ESPs have been capped for a while. There is at least potential legislation that would uncap ESPs. Do you have a sense at this point what that might mean to your forecasts of either Edison load or CCA load?

MR. MARTINEZ: No. That's a great question, it's actually a really interesting question. Our forecasts and RIOs, we haven't done anything (indiscernible) last four or five years. Since I've been involved with forecasting we've always assumed that DA was going to remain capped as (indiscernible) at its current level.

CHAIRMAN WEISENMILLER: Okay. Well, fine if obviously as we move forward, and this might be more of an issue for next year than this year, certainly we want to encourage you to discuss the issues with the staff on what could happen to ESP growth in general and how that might interact with the CCA growth.

MR. MARTINEZ: Sure.

CHAIRMAN WEISENMILLER: Okay. Thanks. Thanks for your help today.

MR. MARTINEZ: Sure.

CHAIRMAN WEISENMILLER: Okay. Thanks. Thanks for your help today.

MS. RAITT: Thank you.

So next we'll hear from Nick Fugate from the Energy Commission to talk about improvements planned for next year's forecast.

MR. FUGATE: Let's see, so good afternoon. My name's Nick Fugate. I'm with the Demand Forecasting Unit in the Energy Assessments Division. So we've had several presentations today on work underway for the 2018 Update. I'm going to wrap things up here by providing a brief high-level outline of some additional work we had planned for the 2019 IEPR and subsequent cycles.

Starting with our residential model, which we use to forecast energy consumption for that sector, but also the end-use detail inherent in that model allows staff to account for and estimate the cumulative impacts of Building and Appliance Standards. We've been doing this for a long time, long enough that the original model was developed in Fortran at a time when processing power and data storage came at a premium. So this made for a somewhat cumbersome implementation that was difficult to improve on, so with things like significant growth in our miscellaneous sector or sorry miscellaneous end use driven by things that are not explicitly characterized in the model. And also like Commissioner McAllister mentioned earlier about electrification of new end uses, it's important that we are able to nimbly make updates to this model. And so we're moving towards a more modern implementation, one that's easier to work with and modify.

And as we do this we'll be considering enhancements to the model. We've retained Dr. James Mann formerly of our Expert Model Review Panel to examine our residential model and recommend levels of geographic and end use granularity that would provide additional value while also being feasible given data availability. And also to review our current approach to characterizing Building and Appliance Standards in the model, and to make recommendations on other potential improvements such as incorporating income and price elasticities, fuel competition and an approach to statistical end use calibration.

And as we consider making, especially the point on characterizing Building and Appliance Standards, as we think about that we'll also be sure to reach out to our Efficiency Division for input.

Regarding load shapes, the Energy Commission has contracted with ADM Associates in coordination with our Research and Development Division to refresh our baseline and use load shapes for each for forecast zone, customer sector, building or industry type as specified by our sector models. As part of that work, ADM is developing generation profiles for behind-the-meter PV systems, efficiency savings profiles for measure categories and charging profiles for electric vehicles.

Because this contract is funded by the Electric Program Investment Charge ADM's analysis is restricted only to IOU service territories. However, as a separate follow-on project staff intend to expand this effort to other utilities and forecast zones.

Ultimately, these new load shapes will be incorporated into a revised peak model. Our current model, apart from needing refreshed load shapes was unable to directly account for impacts from load modifiers such as PV. The revised version will be able to do this, so newly revised Title 20 data regulations will enable the Energy Commission to receive interval meter data from LSEs starting next year. This will allow staff to enhance our 8760 Load Analysis specifying early models for load serving entities besides the IOUs or for regions of interest within an IOU territory.

It will allow for customer sectors to be modeled individually. Each sector has a different characteristic shape to it and so the extent that we are projecting consumption in one sector to grow more than another, the contribution of each could be more reasonably reflected in the overall forecast.

We also explore the possibility of incorporating adjustments to account for climate change. Chris touched on this earlier. It will involve projecting changes in temperature at an hourly level. Staff have -- we've engaged a little bit with Scripps on this and they've indicated they may be able to provide us an analysis of hourly temperature changes due to climate change. But this is very preliminary at the moment, once we have a concrete proposal we'll have to work with stakeholders in DAWG to assess its reasonableness.

On efficiency, we've begun preliminary discussions with CPUC staff to better understand the nature of their new rolling portfolio framework for Energy Efficiency Program implementation and what that might mean for our definition of committed savings. In past cycles, the committed period extended only through the end of the CPUC's three-year funding cycle. Now the utilities have approved ten-year business plans, however specific implementation plans, the kind that have detailed measure level information that we usually rely on to develop savings estimates for our forecasts, these types of plans are still approved on a much shorter timeframe. So staff will have to make a determination as to whether the ruling portfolio framework provides us enough certainty, enough confidence even if only for some subset of relatively consistent programs that we can carry those savings forward into the ten-year funding horizon.

On the additional achievable side of the equation we have an update to the CPUC's Potential and Goal Study expected next year. This project is still in the solicitation phase, but the current thinking is that the AAEE scenarios can be developed in time for the 2019 Forecast period provided there are no delays to that process.

Of course, the IOU potential study is no longer our only input for AAEE. For POUs we have Navigant under contract to produce savings estimates. 2017 was the first forecast cycle for which we developed AAEE scenarios for POUs. And in that initial effort there some shortcomings, notably only a single projection was developed with no variation across scenarios. Staff is still working with Navigant to create an approximation to the scenario design approach that we used for the IOUs, so that we have a comparable spread in potential savings estimates.

And to the extent that the analysis of potential savings from nonutility programs such as similar to the NORESCO analysis that was developed under contract with our Efficiency Division, to the extent that those types of analyses become available we will work to translate those into complimentary additions to the AAEE Forecast.

And let's see, it occurs to me this final bullet's not clearly stated. I'm intending to talk about the disaggregation of AAEE to load buses. This is a significant analytic undertaking, which strains both our forecast schedule and staff resources. And so we've asked the ISO to investigate the extent to which POU savings allocation of load buses impacts their power flow modeling. And depending on the answer to that question, we'll ramp our effort either up or down.

So Sudhakar talked about this a little earlier, we've adopted Title 24 Building Standards requiring solar and new homes, so for 2019 that will be the forecast cycle where we move the AAPV into the baseline forecast along with incorporating the efficiency component also into our models.

Our analysis of behind-the-meter storage adoption is not very sophisticated at the moment due primarily to a lack of historical data to analyze. We can further develop our expertise with this technology through literature view and consultation with experts, analysis of the project data we do have available to date. Through these efforts we hope to begin to develop at least a framework for predictive adoption model going forward.

And as a supplemental piece to the 2017 IEPR staff performed a preliminary analysis of potential incremental load growth due to cannabis cultivation for newly legalized marijuana consumption or recreational consumption. This is another area where we did not have much historical data to analyze at the time and we mostly had to consider the experiences of a handful of other states who went before us. And even then there was not enough uncertainty around those preliminary projections that we felt we could include them in the forecast. But two years later we'll have some additional load data, new service requests from emerging cultivators and initial studies and reports of activity in this area. So we should have some more data to work with and we'll attempt to refine our analysis and include projections for cultivation demand as part of the 2019 Forecast.

And finally we have three major surveys that inform our forecast: the California Vehicle Survey on the transportation side and then the RASS and the CEUS, which we use to update end use saturations and energy intensities in our residential and commercial models. From conception to completion these are multiyear projects. While surveys are in various stages of development or execution in all three cases we could see results translated into model adjustments for the 2020 -- as early as the 2021 IEPR.

And this is my final slide. I'm just going to talk a little bit about process alignment. One relatively new forecast dependency arose from a CPUC decision issued earlier this year, which identified the IEPR Demand Forecast as the default set of DER growth scenarios that the IOU should use in their distribution system planning.

The CPUC also initiated a Limited Term

Distribution Forecast Working Group to review and discuss the methods of the utilities we're using or will use to disaggregate our DER projections down to the circuit level. Staff participated in this working group and we've committed to remain engaged with the distribution planning process. Staff see this as an opportunity, you know especially working with utility analysts, to share information and modeling approaches as they pertain to DER forecasting.

Additionally, the JASC has identified some issues of alignment between the IEPR forecast in some of its dependent proceedings such as the IEPR and resource adequacy. One of these issues has to do with the timing of the proceedings, the CPUC and ISO have expressed a preference to have the Year Ahead Peak Load Forecast delivered earlier than our typical January forecast adoption. However, our own schedule is driven by a need to reflect the most recent summer peak in our analysis.

Staff recognize that one potential solution could be to create a separate parallel process narrowly focused on just developing the Year Ahead Forecast that incorporates the summer peak. And at the time of its creation is in alignment with the IEPR Forecast.

The separate Yeah Ahead Forecast would be, you know, then subject to a streamlined vetting process and could potentially be transmitted earlier, say in November. But there are some things to consider. That effort would be contingent on having first the staff resources to go through this separate process without impacting the IEPR schedule. And additionally, we'd then have two separate forecasting processes and even if they're closely linked that creates a space for discrepancies to emerge.

And in the event that RA moves to a multiyear process, the value of this approach is kind of unclear. Also, while our forecast schedule is anchored to that summer window, it may be worth examining at what points are anchoring these dependent proceedings and seeing if there's any room to shift those schedules.

Another alignment issue was the monthly peak projections. I'm not going to say much about that, because Chris went over it in his additional slides. I'll just say in our JASC discussions we are hearing a preference to have the -- to move towards a consistent sort of approach to projecting monthly peaks, one that's vetted and adopted through the IEPR process. So we'll continue engaging with JASC and DAWG on both these issues.

CHAIRMAN WEISENMILLER: Thanks. Yeah, I'm glad you have not only the IEPR and RA issues, but also the DER issues. You know, as I understand it there's one set of coordination issues or process alignment issues on the IEPR and RA and then there's actually a different timeline associated with DER. And all three of which would like to have something that feeds into their process that's sort of updated and ready to roll in the different timelines for those.

I think one of the things we need to explore is sort of -- but again, it's a different set of issues. Certainly, just a lot of our resource issues is that the overall forecasting model was designed to really pick up structural changes that result from Building Standards, you know, all the things, Appliance Standards. All of the things we're doing, which is really a long-term forecast model.

The short-term forecast you would not expect to see as many structural changes in the next couple years say, but something that's much more driven by weather and the economy. So there might be some advantages to having more an econometric approach short-term, a detailed model longer term. But then as you pointed out, somehow you're going to have the two fit together smoothly. But, I mean that's part of the issue.

I've always thought on the RA issues it's possible to look at the short-term part of the last adopted forecast, again under the theory that you would not anticipate as much uncertainty or changes in the next say couple of years as you do ten years out. And typically when you look at the adopted forecast they're remarkably close together; you know, this year's adopted forecast and the last one as you compare those. So you may be able to get a head start on some of the RA processes along the line, although I think what we've heard today is things like the CCA splits where certainly it could be much more important than some of the other model changes that go on in each of the annual update.

So there may be some simple updating processes that you could do, but I think as Edison demonstrated the CCA numbers are changing pretty fast and certainly much faster than most of the components of the forecast. So again, I think there's obviously a lot to be determined looking forward, and I would say as Andrew has already noted, the need to start thinking more on the updates on electrification although, obviously a couple of houses with heat pumps don't really affect the model per se at this stage even though they might be Commissioners.

But at the same time I think longer term that's something we have to factor into and obviously Commissioner McAllister is very interested, as we get better and better data, how that might help us evolve the model structure, since I think all of (indiscernible) building stock information that until you get the RASS or CEUS done.

They're like a decade out of date.

MR. FUGATE: Right.

CHAIRMAN WEISENMILLER: Yeah. So a lot of work to do, but I certainly appreciate all the work that goes on here trying to get all the little details of the forecast correct since they do really matter, is the bottom line. So again I think it's been an area for a lot of work over the -- since the Energy Commission was founded. But I think it's going to really keep people busy for the next couple of decades, really trying to follow the changes in the market structure and the structure opportunities here. So thanks.

MR. FUGATE: Thank you.

CHAIRMAN WEISENMILLER: Okay. So at this point we'll go to public comment. Delphine, please?

MS. HOU: Good afternoon, Chair, Advisors, Delphine from the California Independent System Operator and we really appreciate all the effort the CEC staff has gone through in engaging with us, especially the important discussions we're having at JASC.

I wanted to make one minor friendly amendment to something Nick said. It wasn't on the slide deck. Obviously, we're discussing the potential of having the RA Forecast one year ahead, but that's not explicitly something that CAISO is advocating or pushing for. We're curious to see how it pans out, but we think that as the PUC moves into a multiyear resource adequacy construct, it's not going to be the one year ahead. You're going to need a couple of years and so we're really looking at the IEPR Forecast, the long-term forecast, as being the vehicle for providing that foundation.

Because at the moment the CPUC discussion is it could be anywhere between a three to a five-year construct, so we're not too sure. So we don't think necessarily a one-year ahead is going to be able to buy us what we really need to be successful in that form. So we want to still focus on what IEPR is doing. But having said that we do want to work together, and collaboratively to maintain process alignment, so we appreciate that. Thank you.

CHAIRMAN WEISENMILLER: No, that's good. Thanks for the reminder.

MS. HOU: Yes. Thank you.

CHAIRMAN WEISENMILLER: I think all of us have looked, obviously at the multiyear RA and I don't know if we quite gave up hope, but it's here now so it's definitely time to think about that. And as you said certainly changes this question of just next year versus the next three to five years. And again, I think it's probably more of a question for Nick and Chris looking at what the deltas are, but again we eyeball the lines as I said going at least 20 years out is not much difference.

MS. HOU: Yes. Thank you.

CHAIRMAN WEISENMILLER: Okay. And we also have Silicon Valley Power, please Erica?

MS. JUE: Hello, Chairman Weisenmiller and staff. I just wanted to thank you all and Chris and his team for working with us and accommodating. Silicon Valley Power is a municipal owned utility and we are quite an outlier, just because the majority of our consumer base is industrial. And 90 percent of that exactly and then 50 percent of our total consumer base is from data center growth. So we found that the growth rates that we're seeing were significantly larger than what we had seen in the IEPR. So we're really happy to work with you and Chris, and have Chris be able to accommodate that.

And then just to pinpoint kind of just the scale of the growth, some of the data centers will come in maybe about 5 megawatts. But we have one of our largest consumers that has data centers with a total capacity of 90 megawatts. So just in terms of the ramps and the load growth we see it to be quite significant in the near future.

For example, our energy growth over the next ten years is about 4 percent on an average annual basis, but looking at the next few years it's about a 10 percent year on year growth.

And then just basically what we're seeing on the ground is that some of the energy efficiency of the buildings themselves have been able to supply capacity. So these data centers are operating at greater than 85 percent load factors with quite high energy efficiency and the ratings for their power usage effectiveness have been below 1.3.

So with that in mind we're seeing, because of the technology changes in data centers and also the design and operation of the data centers we're seeing that just the energy that's the per square foot is also increasing, which is increasing the load per. The square miles of the total service area of Silicon Valley Power.

So we're moving forward. We're just looking forward to working with you and Chris and his team on developing these demand forecasts, especially in getting into the more granular data. So should there be an opportunity that you would need us to provide data we're happy to work with you. So just wanted to thank you and the team.

CHAIRMAN WEISENMILLER: No, thanks a lot for your help in this area. I know, I think it was Chris's slide if I remember right, it was like a difference between 3,000 and 4,000 megawatts in terms of the data center effects, so it's a pretty significant effect. And obviously that's good for California to have that much interest in data centers. And obviously even more generally with Silicon Valley Power I notice that the Shenzhen Incubator launching and Silicon Valley Power, and again the sense that you're really capturing a lot of the innovation space and the technology and I'm sure it's important for you to have -- or for both of us to have good forecasts, but also if you have a very reliable system.

MS. JUE: Right, exactly. So thank you.

CHAIRMAN WEISENMILLER: Well, thank you.

Anyone else with public comment either in the room or on the line?

Please come on up, fill out a blue card or at least identify yourself for the court reporter.

MR. BYSTROM: Good afternoon, is this one? Yeah.

CHAIRMAN WEISENMILLER: Sure.

MR. BYSTROM: Let me introduce myself. My name is Olof Bystrom. I'm with SMUD. My comments are more with respect to the usefulness of the IEPR for the -- an IRP process since it's now being used for that.

And I had just three comments to encourage more detail in the IEPR. So as we look at it, the first one is with respect to load shapes. So right now when CCAs are forecasting their load and submitting this to the CPUC they're using a fairly aggregate load shape, which is useful I suppose when we look at California as a whole. But less useful for an individual load serving entity just because it's frankly not detailed enough to be used for the type of long-term planning that the PUC is requesting.

And that goes into the two comments around this then too, would be to as we look at EV adoption and additional behind-the-meter solar for example, that's likely to be very different depending on which CCA we're talking about, depending on demographics, economics, disadvantaged groups and so on. So having that factored into whether that's load adjustors or just the load forecast itself would make the IEPR, I think more useful.

And then finally just a short comment on demand and demand relating to economics. Just wondering how the pricing is factored into the load forecast, because one, a couple of drivers that CCAs have is the fact that they're offering a more competitive price than the incumbent IOU. So it's that factored into any of the --

CHAIRMAN WEISENMILLER: But they can -- (indiscernible) one or two (indiscernible) counts off of what the --

MR. BYSTROM: Yes, that's true.

CHAIRMAN WEISENMILLER: And that's not -- come on, that's not particularly (indiscernible).

MR. BYSTROM: That's probably not material. I'm just wondering if it's factored in, is it's more a question or maybe a comment that that might be useful to have. So whether that's a major issue or not I couldn't really say, but I guess then the gist of these comments is that the more granular that we can make the IEPR with respect to each CCA and in particular with respect to load shares, the more useful it would be.

CHAIRMAN WEISENMILLER: Well, again give your business card to the court reporter. I appreciate your comments on that. I think the reality is you've heard from the staff that generally the data comes in at a county level, you know. And that may or may not fit a CCA, many of them are smaller than full counties, then you get to can you get to zip code level. And again, the data aren't there at this stage.

And as far as I can tell on the CCAs, they're a very small group. I mean, Sonoma said they have three people doing the power procurement and risk assessments, so I'm not sure how much load data they're ever going to collect on some of this stuff. But I mean, the better data we get from the CCAs the better we can do those forecasts. But again, it all goes back to data and methodology of resources.

So anyway to the extent SMUD is working with some of the CCAs if you can encourage them to be developing the tools they actually know what's going in their market, right?

MR. BYSTROM: Thank you.

CHAIRMAN WEISENMILLER: Anyone else?

MS. RAITT: So --

CHAIRMAN WEISENMILLER: Anyone on the phone?

MS. RAITT: Yeah, we'll go ahead and take a minute to open up the phone lines, so if folks on the phone wanted to make comments it's your opportunity.

Okay. Hearing none, I think we're done.

CHAIRMAN WEISENMILLER: Yes, I think we're done with public comment.

I think in terms of at least my comments have already hit the basic point that I think the forecast is very important to us. At this point I'd have to say that, and certainly working on the process alignment is important. I think the message in all these areas has bene that there is lots of uncertainty. I think the CCA part is probably among the most uncertain, but certainly let's not overlook the uncertainty on forecasting say PV adoption or SUV adoption, you know, all the other pieces.

I think this is going to be a continuing focus. And it's important to be developing the basic data we need and tracking what's going on in the real markets, so we can use that to get better models and better forecasts going forward in this update.

I think next year's forecast we'll have the opportunity for digging in a lot more substantially, particularly as we get some of the data back from hopefully CEUS or RASS, but from the other pieces.

So again, I want to encourage everyone to provide their public comment on this, particularly anyone who can step forward with better data than we have there already. That would be very useful and I'm sure staff will be happy to work with you on it.

MR. RIDER: I just want to say thank you to staff for the wonderful presentations today. And thank you for those who have traveled here, who don't work here, for coming to provide your comments and ask informed questions.

MR. CALDWELL: Yeah, just as Commissioner Scott's office being the Lead on Transportation we look forward to continuing to work with the Transportation Forecast Team. Last year we did a lot of good work and so we look forward to build on that, so thank you for the presentation today.

CHAIRMAN WEISENMILLER: So this meeting is adjourned.

(The workshop was adjourned at 1:05 p.m.)

REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and

place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of July, 2018.

PETER PETTY
CER**D-493
Notary Public

TRANSCRIBER'S CERTIFICATE

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

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of July, 2018.

____

Myra Severtson
Certified Transcriber
AAERT No. CET**D-852