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STATE of CALIFORNIA

NATURAL RESOURCES AGENCY

CALIFORNIA ENERGY COMMISSION

In the matter of:	Docket No. 20-IEPR-03
2020 Integrated Energy Policy Report Update (2020 IEPR Update)	RE: Energy Demand Forecast

Transcript of the

IEPR UPDATE COMMISSIONER WORKSHOP

Sessions 1 and 2

held remotely by the

California Energy Commission
Warren-Alquist State Energy Building
1516 Ninth Street
Sacramento, California 95814

Thursday, December 3, 2020

In accordance with Executive Order N-29-20 and Executive Order N-33-20, the physical location was canceled and the meeting was held via the Zoom video/audio internet and via teleconference platforms.

Reported by:
Susan Palmer, CET-124, CER-124

APPEARANCES

Commissioners:

J. Andrew McAllister, Lead Commissioner for the 2020 IEPR Update Demand Forecast
Patricia Monahan, Lead Commissioner for the 2020 IEPR Update
Janea A. Scott, Vice Chair

Karen Douglas

Presenters:

Aniss Bahreinian
Mark Palmere
Bob McBride
Alex Lonsdale
Sudhakar Konala
Cary Garcia
Nick Fugate

I N D E X

P R O C E E D I N G S

December 3, 2020 10:00 o'clock a.m.

MS. RAITT: So good morning. Looks like it's ten o'clock, so we'll go ahead and get started. Welcome to today's IEPR, the 2020 IEPR Update Commissioner Workshop on the California Energy Demand 2019-2030 Forecast, the Update to it. I'm Heather Raitt, the Program Manager for the Integrated Energy Policy Report, which we refer to as the IEPR.

Today's Workshop is being held remotely, consistent with Executive Orders N-25-20 and N-29-20, and the recommendations of the California Department of Public Health to encourage physical distancing to slow the spread of COVID-19.

Instructions for attending or participating in the meeting were provided in the Notice and are included included both internet and call-in options. The Notice is available on the Energy Commission's webpage.

So we split this topic into two sessions to help encourage participation. This morning's session focuses on transportation energy demand. Session 2 starts this afternoon at two o'clock and will be on self-generation and the overall Electricity Demand Forecast update. And for the afternoon a separate login is required.

All IEPR meetings are recorded. A copy of the recording and a written transcript will be available on our website in a few weeks. And copies of the presentations have been docketed and are available on the Energy Commission webpage.

So this morning we'll be using the Q and A function in Zoom with the capability to vote on questions posed by others. So if you have a question for the speakers, attendees may type the questions and press the Q and A icon to do that. And then before typing a question, you might check and see if there's another one like it. And, if so, you can click the thumb's up button to vote on it. And that will vote it up onto the top of the list.

We'll try to reserve about five minutes at the end of the two blocks of presentations this morning to address the Q and A from attendees. And given the time restrictions, we're unlikely to elevate all questions received, but you're also welcome to submit written comments. And I'll go over how to do that.

So at the end of each of the morning session and the afternoon session will be an opportunity to submit comments. So you can use raise your hand, use the raised hand icon to let us know that you'd like to make a comment. And we will be able to open up your line at the end of the meeting. And if you're on the phone, you can press star 9 to raise your hand, and we'll open up your line at the public comment period. And, alternatively, you can submit written comments and those are due on December 17th at 5:00 p.m. And the Notice gives you all the instructions for how to do that.

And with that, I will turn it over to Commissioner McAllister for opening remarks. Thank you.

LEAD COMMISSIONER MCALLISTER: Great. Well, thank you very much, Heather.

I am really happy to be here. Obviously the forecast in all of its facets, and it's a huge endeavor with lots of staff involved, I want to just thank all staff that sits behind the work that we're going to see today, the transportation side in the morning and the overall forecast in the demand forecast this afternoon.

And Aniss and all the presenters for this morning, I want just to thank you. This is obviously a large team effort.

Really happy to have Commissioner Monahan here, who is a lead on the topics for this morning on the transportation arena of the Energy Commission.

So thanks for joining us, Commissioner Monahan.

So really looking forward to everyone's attention and questions. There is a lot of substance. This morning, we're going to just -- we're going to see a lot of topics covered in the presentation as well as this afternoon. And I just want to make sure everyone knows that they have the opportunity to comment today, but also to submit comments, written comments later, after the workshop, after they've had a chance to really delve into the substance.

So with that, I think I'll pass it on to Commissioner Monahan to see if she has any -- any opening remarks. Obviously this is the bread and butter of what the -- what the Energy Commission does, and so we want to make sure we get it right. Transportation is given the executive order and all of the activity that's noteworthy there, so just a lot of good stuff to talk about in terms of California's leadership and where we're going with this and its impact on our energy systems.

So over to you, Commissioner Monahan.

COMMISSIONER MONAHAN: Thanks, Commissioner McAllister.

Well, I'm very excited to see the data that's coming out. There was some question about whether we would be able to see data today, and it seems like the team has been able to work some magic, some mathematical magic to make that happen. So really curious to see the results of the modeling.

And, yes, as Commissioner McAllister said, as we, you know, come off the heels of the Governor's executive order announcing that we are transitioning to a zero-emission vehicle fleet that's for everything, light-duty vehicles, passenger vehicles, off-road equipment, heavy-duty vehicles. And, as we all know I think on this call and this Zoom call, transportation is the number one source of global warming pollution. It's also the number one source of toxic diesel exhaust and smog, nitrogen oxides, especially for the heavy-duty fleet.

So there is just a lot of reasons we need to focus more intently on curbing transportation pollution, setting a course for zero emission. And I think we have some new ones in terms of dropping battery prices, expanded investments in fuel cell electric vehicles. So really looking forward to this morning and to this afternoon, that as Commissioner McAllister said, this is the core of what the IEPR is, is really projecting demand and helping our sister agencies plan for energy needs.

So with that, I'm not sure if there are any other Commissioners on the dias. It seems like -- is there anybody else, Heather, that --

LEAD COMMISSIONER MCALLISTER: I think we're excepting Commissioner -- or Vice Chair Scott in about an hour, but I think that's about it for now.

COMMISSIONER MONAHAN: Okay.

LEAD COMMISSIONER MCALLISTER: Yeah.

COMMISSIONER MONAHAN: Okay, great.

All right. I'll turn it back over to you, Commissioner McAllister.

LEAD COMMISSIONER MCALLISTER: Very well. Thanks very much. And I'm glad to say I do -- I do lead the forecasting effort at the Energy Commission and so really it's an intensive thing, but it also really is a great perch for getting a view, sort of an integrated view across all the sectors that we do policy and planning for at the Energy Commission. And I'm just continually impressed at the level of the staff and the collaboration across agencies to gather data and also just the analytical chops that we're -- that we have already and that we are developing even more as we move into more data-rich environments each IEPR cycle.

And, just as a reminder, this is an IEPR, an update of the forecast. Next year we'll be doing a full forecast. And this afternoon we'll be talking about some of the challenges of the Covid era and what uncertainties that has sort of injected into this process. And so I think it's important to have situational awareness right now. You know demand patterns have shifted in this relatively radical way due to this radical situation that we're in with Covid and the demand and the behavior changes that we've all had to make. So our buildings and our transportation patterns and our just behavior generally has morphed in ways that we're trying to understand. And so that is a subtext, a very strong subtext of the conversation today. And I'm sure people will have some appreciation of those challenges as well as we talk about those. And we're aware of that, together with our sister agencies that have to consume the products that we make as part of the demand forecast in its various facets.

So it's a really unprecedented time. It's exciting in some ways, but with excitement comes a little uncertainty, a little risk, so you know we're embracing all of that, and staff is really doing a great job of rolling with the evolution of the reality that we're in, so I want to appreciate them as well.

So I'll pass it back to you, Heather, and we can get started on the presentations.

MS. RAITT: Great. Thank you.

So I'd like to introduce our first speaker, Aniss Bahreinian. Aniss is Lead Forecaster on the Light-Duty Vehicle Forecast and Technical Advisor on the overall Transportation Forecast.

So Aniss has two presentations, the first one on Energy Demand Results and the second on Light-Duty Vehicle Stock Results. And I'd like to suggest that we hold questions until after the first set of presenters, Aniss, Mark, and Bob, have finished their presentations.

So go ahead, Aniss. Thank you.

MS. BAHREINIAN: Good morning, Commissioners and stakeholders. I would like to talk about -- the next slide, please. My name is Aniss Bahreinian and I work on the Transportation Energy Forecast at the Energy Commission. And this morning I'm going to make a presentation on Transportation Energy Demand Forecast. So we are focusing, we are starting out with energy which is actually the final outcome of all of our forecasting.

In the beginning and as we move through the day, we will see all the other elements of this transportation energy demand that has been forecasted in different sectors. Next, please. Next slide. Next, please. Okay. Thank you.

We are going to start off with a short discussion of the impact of Covid on fuel consumption. We are going to move on to a short discussion of models and scenarios. And, finally, we are going to talk -- look at transportation energy demand from multiple angles. And then we end it with a discussion of the ZEV Transportation Energy Demand Forecast.

And the other Transportation Energy Demand Forecast as well as the transportation energy prices are in the Appendix, for those who are interested. Next, please.

And this is just a reminder for us to see that transportation energy consumption is a three-legged stool depending if we're standing on vehicle population, vehicle miles traveled, and fuel economy. A change in any policy or any event that is going to affect any one or more of these three different factors is going to alter the transportation energy consumption, as you can see in the subsequent slides.

Next, please. Next. Thank you. Oops, the previous one. If you could, please -- thank you.

These are monthly fuel consumption of Senior Fuel Specialist Gordon Schremp has put these graphs together. These are from his presentations. And what they show is the short-term impact of Covid. Now notice that Covid is going to have a long-term effect as well as a short-term effect. We don't -- there is a lot of uncertainty about the long-term effect, and actually we are going to have a workshop early next year, inviting different experts to discuss the long-term impact of Covid, but these two slides are showing the short-term effect of Covid on gasoline and diesel consumption.

Both of these, on the vertical axis, you are going to see the mean million gallons of consumption per day. And, as you can see in the graph on the left-hand side, it shows gasoline consumption, monthly gasoline consumption. The bars are representing monthly gasoline consumption in 2020 and the two lines above are showing the lows and the highs over the last five years, between 2019 -- 2015 to 2019.

As you can see here, the gasoline consumption bottoms out in April. April was the month when the entire country was shut down and you could see the clear impact of Covid on consumption and gasoline consumption.

Notice through that in this month, the impact of Covid are both on supply and demand. The impact on supply was in the form of the factory shutdowns where production of vehicles and other transportation, fuels, etc., was going down because of the factory shutdowns. And we all heard about this disposition and the impact of shutdown on EV production and EV Pro that they use, but the number you see here in April is entirely related to Covid. It's entirely related to the PMT reduction because people were not working and PMT declined significantly and, as a result, you could see the significant drop in the consumption of gasoline.

As we move on from April to May, June, and July, we could see that the consumption gradually recovered, but even in July we are still seeing that the consumption remains below the five-year lows of gasoline consumption, so it is still there even though we are covering from April and because of the economic slowdown.

On the right-hand side we would see the impact of Covid, the short-term impact of Covid on diesel consumption. You should note that while gasoline is the predominant fuel for light-duty vehicles, diesel is the predominant fuel in the medium- and heavy-duty vehicles, which are used mostly for mass transit as well as movement of goods. So as you can see here, the decline in diesel demand is not as sharp as the decline in gasoline demand. There are more long-term contracts, for instance, in goods movement involved. And, on top of that, there was also a significant impact on deliveries because people were staying home. They were not going to stores, for instance. There were a lot of deliveries that happened. And so -- and those deliveries are happening in the medium- and heavy-duty vehicles which is going to drive up the demand for diesel, from that perspective.

As you can see also that while the bottom was reached in March and April for diesel consumption, in May, June, and July you could see that demand is recovering and actually in this case, in the case of diesel, we are getting -- we are slightly above the five-year lows that we have seen in the red line. So diesel is not impacted as significantly as gasoline, but it is still showing the impact of Covid on diesel consumption. Next slide, please. Thank you.

This diagram shows the different models that we are using in generating an energy demand forecast. There are about the 10 key models that we are using. Some of them are for vehicle demand, for instance, personal vehicle choice and commercial vehicle choice, as well as government and rental and the truck choice. These are vehicle demand models. But then some of them are travel demand models, like urban in the city, freight and other bus. These are mostly used in the forecast for travel demand.

And aviation is another travel demand. And you should notice that an aviation model was not used for the 2020 IEPR. We just didn't generate a forecast for aviation demand, although you can imagine that impact on the aviation sector was huge. A lot of airline companies went out of business -- well, they got into financial condition that needed help from the federal government, so there was a huge impact on jet fuel demand. But we don't -- we didn't include it in this forecast.

And other travel models, like in the city and urban for instance, they didn't go to as much of input changes as we did for the vehicle choice models. The freight model also included major input updates, and therefore we are showing the impact of -- the impact of Covid on travel demand is mostly captured through the economic and population changes. Economic impact and population changes. Next, please.

This slide shows the green scenarios that we are using for all of those 10 different models that we have. Notice that our main and general plan is the electricity demand forecasting unit, and therefore our scenarios are aligned with their scenario. And what we refer to as a high-demand case here is actually high-electricity demand.

As you can see here, in the high-electricity demand case, we are combining the high income and population growth with high petroleum prices but low electricity prices. So it is a clear indication that these scenarios are actually aiming for high electricity demand. The reverse is true in the low demand peaks. It is a reflection of low electricity demand, and we are combining the high electricity prices with low petroleum fuel prices and low economic and population growth. Next, please.

This graph shows the distribution of fuel types by vehicle type. The graph on the right-hand side shows the distribution of fuels for light-duty vehicles and the graph on the left-hand side shows the distribution of fuels for the medium-, heavy-duty, and rail. In the light-duty sector, as you can see here, gasoline is the dominant fuel and forms 96 percent of total fuel consumed by light-duty vehicles.

On the other hand, when you look at the graph on the left-hand side, you could see that diesel is the dominant fuel in that sector, in the medium-, heavy-duty sector, and it forms 85 percent of total fuel consumed by medium- and heavy-duty as well as rail.

The third-place ranking for light-duty vehicles on the right-hand side goes to electricity, and we are talking about electric vehicles obviously here, but on the left-hand side, the third-place ranking for fuel goes to pipeline gas. And pipeline gas is mostly used in transit. These are 2019 data, so these are actual data. And the pipeline gas in the medium- and heavy-duty sector mostly goes to transit sector and also some vehicles in fuels in trucks that are used by different utility districts as well as some in other parts. Next, please.

This graph shows the -- it is sort of along the same line but compares the 2019 distribution of fuels to 2030 in the high-demand case. So the 2019 is the actual data, 2030 is the high-demand forecast. And we are using the high-demand forecast because you can see the impact of ZEVs on -- in the high-demand case better than in other cases.

As you can see here, when it comes to gasoline, there is a decline between 2019 and 2030 in gasoline demand. This is mostly in the light-duty sector, obviously. And, as you can see here, when you look at the electricity, the electricity is going up in 2030, compared to 2019, showing the growing transportation electrification and mostly in the light-duty sector.

On the other hand, diesel stays relatively steady, with a slight increase, as was the case with pipeline gas, and there is a small increase in pipeline gas and those that are related to trucks. And a lot of the transit buses are due to change from pipeline gas to electricity. Next, please.

This slide shows the Total Transportation Energy Demand Forecast, but it is converted to BTUs. So we are adding everything, gasoline, diesel, ethanol, electricity, natural -- pipeline gas, hydrogen, and everything. And so it shows that over the time, for all three scenarios, what we see is a decline in total energy -- transportation energy consumption. This is significant in light of the fact that both vehicle population and human population is growing over this time and still transportation energy consumption is showing a decline. This indicates the growing efficiency in this sector as a result of all the changes that they face, whether it is the fuel economy of vehicles or for other factors.

This graph is showing the Transportation Hydrogen Demand Forecast.

Let me go to the previous graph, please?

Let me go to -- no, the previous graph, slide number 11. Slide number 11. And we go to Transportation Energy. I can't see it right on my computer, but --

MS. RAITT: I think she's just getting them back up for you, Aniss. It'll just be --

MS. BAHREINIAN: Okay.

MS. RAITT: -- it'll just be one moment, please.

MS. BAHREINIAN: Okay.

MS. RAITT: Thanks.

MR. COLDWELL: And, Aniss, it's Matt. I just want to do a time check. You said you can wrap up here --

MS. BAHREINIAN: Sure.

MR. COLDWELL: -- in the next couple minutes. Thanks.

MS. BAHREINIAN: We only have two slides on this now.

MR. COLDWELL: Great. Thanks.

MS. RAITT: There you go.

MS. BAHREINIAN: Okay. All right. And so you can move to slide number 11 -- number 10? Yes. Thank you.

This one shows the Transportation Electricity Demand Forecast. And as we can see that there is a wider spread between the low and the high in transportation electricity, showing the higher growth rate in transportation electricity compared to other fuel types. Next, please.

And this -- this graph shows the Transportation Hydrogen Demand Forecast. And this one also shows the wider spread compared to other fuel types. And we are growing from about two million kilograms in 2019 to about 37 million kilogram in 2030. And you can find the rest of the fuel types in the Appendix. Next slide, please. Thank you.

And this is our Transportation Forecasting team, as the Commissioner mentioned. It is a big team and it takes a village to generate a transportation energy demand forecast. And we have a group of talented individuals who are working with us on different forecasting in the transportation sector.

Thank you very much.

Next presentation, please, Light-Duty Vehicles. All right. Thank you.

This group of slides are focused on the Light-Duty Vehicle Demand Forecast. Next, please. Next slide, please. Thank you.

We are going again to talk about some of the Covid impact on light-duty vehicles and then we are going to move on to a discussion of -- a brief discussion of model inputs and scenarios. And then we are going to end it with a Light-Duty ZEV Forecast. And in the Appendix we have all the other light-duty forecasts. Next slide, please.

All right. So this slide is based on data from California New Car Dealers Association, the NCDA. And what it shows, it shows the new vehicles sold in California from 2008 to 2019. And then they have an estimate for 2020 based on the first three quarters of the data and a projection for 2021. As you can see here, the light-duty vehicles reach their peak in 2016 at 2.21 million vehicle sales, but they start declining from 2016. But the rate of the decline is rather slow. However, as you can see here in 2020, there is a significant decline, going down from 2.09 million new vehicle sales to 1.67 million new vehicle sales. And this is clearly the impact of Covid. Covid has had impact on the sales of vehicles, new vehicles.

And if you look at the left -- on the right-hand side, on the graph on the right-hand side, you could also see that used vehicle sales have also gone down. While the new vehicle sales have gone down by about 25 percent, used vehicle sales have gone down by about only 8 percent. And so the decline in used vehicles is not as significant as in the new vehicle sales. And it shows that demand for vehicles, people who are buying vehicles have shifted more towards the used vehicles. And we have seen, for instance, from Manheim data, Manheim is national vehicle auction data, that their index of used vehicle prices have gone up by about 30 percent in the first few months of the year. Although in the fourth quarter, this is starting to come down.

So the price of both new vehicles and used vehicles have gone up. Used vehicle prices have gone up more significantly than the new vehicle prices, which means that it has some equity implications. Usually the people who are buying used vehicles are in the lower-income category compared to those who are only buying new vehicles. And clearly the increase in the price of used vehicles is going to have an adverse impact on low-income households. Next, please.

Now we have seen that -- that the new vehicle sales have gone down, but what about the ZEV vehicles. You see here, for instance, in 2020, through the month of September, and this is based on our own data, and the announcement this just engaged us on new data, you can see that actually even though the new vehicle sales are going down, the share of the ZEVs are increasing in 2020 to more than seven percent. So this indicates that consumer preferences for ZEV vehicles and, in particular, for BEVs are growing over time. And you see a drop in PHEV and a drop in FCEVs, FCEVs, but the BEV vehicles are growing faster than the other ZEVs. Next, please.

You saw in slide 5 of the previous graph the diagram for all the new models. This slide is focusing on the light-duty vehicle market. The staff divides these, the markets in four different segments: Residential, commercial, government, and rental. And the key inputs in these models are the economic and demographic data; the government incentive, which is federal tax credit actually giving access, etc.; vehicle attributes, such as vehicle price, range, and fuel cost per mile, and others; and as well as consumer preference, which is based on our own survey of light-duty vehicle consumers, what might be the buyers. Next, please.

So we saw those categories of inputs, but it is also important to note which one of the inputs are going to determine which aspect of the forecast. When it comes to fleet size and new vehicle sales, with the economic and demographic forecasts that are going to influence the size in new vehicle sales, once that is determined, then the new vehicles are distributed to different fuel types and classes by using the vehicle attributes, federal and statewide incentive, as well as the consumer preferences. So these three groups of inputs are determined in the fleet composition. That is, which classes of vehicles people are buying and which fuel type or power train they are purchasing. Next, please.

The key input changes compared with 2019 forecast. Well, we obviously changed the economic and demographic forecast. We have a new fuel price forecast that we saw in the Appendix of the previous slide, but we also have updated the vehicle attribute forecast. Incentive changes are for state and California Vehicle Rebate Program. The amount was reduced by $500, which is going to have an adverse impact on the sales of ZEV vehicles. But before they went ahead and reduced this amount to reflect the fact that CVRP data shows that not 100 percent of the ZEV buyers are actually qualifying for rebates. And so we reduced the amount to correspond to the data in CVRP. And in order to be conscious of our sister agency CARB, CARB's use of the CVRP. This is going to further reduce demand for ZEV vehicles, because we have reduced the amount of the debate. But then, on the other hand, we have added the Clean Fuel Rewards Program, which is increasing rebates for us. We are applying the program thru rebates, and that is going to push the ZEV vehicle forecast up. So we have two changes that we have made that reduces the ZEV sales and the final one is going to increase the ZEV sales. Next, please.

So this -- this graph here shows the Light-Duty Vehicle Population Forecast. Notice here that the light-duty vehicle population goes up from about 30 million in 2019 to about 35 million in 2030. Note also that the spread between the low and the high cases is very narrow. This is a reflection of the fact that population economic forecast, the spread between those forecasts in the high and the low case is also narrow. So it is actually a reflection of the economic and demographic forecast. Next, please.

And in this graph we have the general scenarios of low, mid, high for all of our different sectors, but when it comes to light-duty vehicles we also get more specific on scenario differentiation for the light-duty ZEV scenarios. In these cases we have generated five different scenarios for the light-duty vehicle forecast. And these scenarios are defined by different elements. One is consumer preferences. In the low case, we are keeping the consumer preference constant at the 2017 level. But in the mid, high, and bookend cases, the consumer preferences grows in the ZEV market share. When it comes to incentives, we have the federal tax credit including packet of federal tax credit; and the California rebate, CVRP; and a Clean Fuel Reward, which we have added this year; and then the HOV lane access.

Notice that CVRP in the mid and the high case is eliminated in 2025. And you could see the impact of this termination actually on transportation electricity demand and you will see the impact also on the ZEV demand forecast when Mark is presenting those forecasts.

When it comes to fuel prices, we have electricity prices that we use from commercial. We are using different rates for the commercial models. And for residential models we are applying the residential rates to the residential model or the personal vehicle choice. And we are applying the commercial rate to the commercial vehicle choice model.

Hydrogen prices have been generated for us by NREL, and they have generated the high, mid, and low prices for us. And we are using their forecasts.

In the 2030 model year attributes, one of the important factors is that we have 15 different classes, up to 8500 pounds per GWR. And in addition to those we also have three different classes for pickups, vans, and SUVs in the 8500 to 10,000 pounds. So you notice here, for instance, that in the high case we are saying that we have BEV in 16 classes of vehicles in the high scenario. What that means is that all of those 16 classes from -- up to 8500 are covered. We have models offered in all of those classes. But in addition to that we are also offering a BEV in the 8500 to 10,000 pickup trucks. And these are based on our new analysis of the announcements where we found different vehicles in different classes -- in different classes of vehicles. We also had a heavy pickup or a light-duty pickup, 8500 to 10,000. In the SUV or, actually to be more accurate, in the FCEV, because we are also -- we are the only agency that generates a forecast of plug-in fuel cell electric vehicles. And this year we had one included in the pickup trucks of 8500 to 10,000.

Vehicle price and battery prices are related to each other. And you can see different battery prices in different scenarios. And the vehicle prices are derived from the battery prices.

We can also see the maximum EV range in 2030. It is about 20 cents in the low case. It's about 385 miles for BEV. And the range for FCEVs is about 460 miles.

With this I am going to end my presentation and move on to the Forecast of Light-Duty Vehicle by Fuel type. Mark Palmere is leading the forecast in light-duty vehicles and he will be presenting the results to you. Thank you.

MR. PALMERE: Thank you, Aniss.

Good morning, Commissioners, stakeholders, and members of the public. My name is Mark Palmere and today I am going to present the Light-Duty Vehicle Population Forecast numbers, including a closer look at each of the -- each of the vehicle fuel types in our forecast. Next slide, please. Could we go to the next slide, please. Thanks.

This slide shows the forecast of light-duty ZEV population in the state of California. While our forecast officially goes out to 2030, we have added a look at 2031 to show when we expect the goal of five millions ZEVs on the road be reached in the aggressive and bookend cases.

As Aniss mentioned, the Covid Pandemic has had and continues to have a significant impact on new vehicle sales. And, as a result, we expect a slight delay in the achievement of some ZEV targets. But at the same time, if we compare this to the total light-duty vehicle stock slides that Aniss shared, while total numbers are going down in 2020, among ZEVs we still see an increase, albeit at a lesser rate than we have seen in the past. And despite this, in all cases but the low case, we do forecast the goal of 1.5 million ZEVs by 2025 to be achieved.

Note that because in the low, mid, and high cases we estimate a phasing out of the state EV rebate in 2025, this graph displays a kink in those lines. We will see the same kink when looking at each individual alternative fuel type. And I won't point it out every time, but you can be sure that that is the reason.

One final point on this slide, as Commissioner Monahan mentioned, the game-changer to California's transportation outlook is Executive Order N-79-20, banning the sale of gasoline vehicles starting in 2035. Because our forecast was planned out before this announcement, this year's numbers do not go out far enough to show this effect. However, we plan to incorporate this development in next year's IEPR by forecasting out to 2035. Next slide, please.

While currently there are a similar number of battery-electric and plug-in hybrid vehicles on the road, we expect to see a greater share of BEVs throughout the forecast period. This is due to a number of factors we forecast to be more favorable for BEVs, including greater model and class availability, better fuel economy, and larger incentives. By 2030, in the mid case we forecast over two million BEVs compared to just under a million PHEVs and about 200,000 fuel cell vehicles. Next slide, please.

Looking specifically at battery-electric vehicles, on-road BEVs surpass two million in the mid case, three million in the high case, and four million in the aggressive and bookend cases. Most of the difference between the aggressive and bookend cases is found in the fuel cell vehicle stock, which we will see later. And, as a result, those two cases do look similar in this BEV-only graph.

While 2020's gain was modest, as previously mentioned, we foresee the recovery becoming as soon as next year and continuing throughout the forecast. Next slide, please.

Meanwhile, as previously shown, the plug-in hybrid gains are less noticeable but still steadily increasing at least after this year. While PHEV stock fails to reach a million by 2030 in the mid case, in the high case it does surpass that mark by 2028. Next slide, please.

For fuel cell vehicles, we see greater variation by demand case. This is because in the aggressive and bookend cases, particularly the bookend case, there are many more classes available and the state rebate known as CVRP is not phase out. And since the fuel cell rebate is $2,500 more than the battery-electric vehicle rebate, we expect the rebate's availability to have a bigger impact in the fuel cell market than in the BEV or PHEV markets. Next slide, please.

And now I'd like to look at the forecast for the nonZEV fuel types. Next slide, please.

While gasoline stock is decreasing this year, we expect it to recover alongside ZEV stock and eventually even begin to increase again. Although stock is going up, as you can see, the share of population is actually decreasing as ZEVs eat into gasoline's dominance. And for those wondering about the lines crossing, the low case initially sees fewer gasoline vehicles than the high case as a result of it having a much more pessimistic economic forecast. But by 2025 that effect gets outweighed by that case being relatively more favorable for gasoline vehicles than ZEVs.

Another way to look at is with ICE vehicles. In the low case, we see fewer total vehicles sold, but a greater share of them are ICEVs while in the higher case we see more vehicles sold but a lower share of them are ICE. And we see cases crossing each other as a result of those two effects varying in strength. Next slide, please.

Meanwhile, diesel vehicles are decreasing in population in all cases. This is mainly due to the decrease in the number of diesel light-duty classes available. Most diesel light car models have been discontinued, meaning as diesel light cars are retired they will not be replaced by new diesels since such classes are not available anymore. We expect the total number of onroad diesel LDVs to dip below half a million in all cases by 2024. Next slide, please.

Flex-fuel vehicle numbers are also forecast to decrease for similar reasons. We forecast that there will be under a million FFVs on the road by 2027. Next slide, please.

However, we do expect hybrid numbers to increase. Many automakers continue to offer these models due to their higher fuel economy and, in fact, we even expect new hybrid classes to be offered in some cases. As a result, we envision them remaining a viable alternative for consumers who list fuel economy as an important consideration when deciding what fuel type of vehicle to buy. Next slide, please.

And this concludes my portion of the presentation. Next up is Bob McBride. Bob leads the Transportation Electric -- Transportation Energy Forecasting Unit, Medium and Heavy-Duty Forecast, and will be presenting an update on those sectors.

Bob.

MR. MCBRIDE: Hello. Just getting my video up here. Very good. Okay.

Good morning, Commissioners, stakeholders, fellow staff and colleagues from our sibling agencies. I'm Bob McBride. This presentation describes the medium and heavy vehicle forecast. While some of the work was a typical update, just getting newer data, we also did a lot of new work that is sort of beyond an update. Next slide, please.

In the 2020 Update and changes, we looked at vehicle retirement in exports, new purchases, and used trucks imported. The ARB HVIP incentive scheme, we have changed how that plays out in the forecast. Economic growth of goods movement is on a different basis now. Total new trucks purchased of course changes as a result of all these retirements and new economic growth and incentives. The ZEV stock forecast follows. And we'll take a look at the total advanced clean trucks manufacturer net credit requirement. On the left you have a chart showing the medium and heavy classes. Usually medium is class 3 to 6, and heavy is class 7 and 8. Next slide, please. Hello, next slide, please. Slide 3, please. Thanks.

For this forecast we used EMFAC 2017 forecast requirement rates, so that's forecast rates for all years and scenarios. The EMFAC forecast data includes imports of used trucks, especially before 2023, with engines from at least 2010, since older trucks can't operate in the state from the end of 2022 forward. In the 2019 forecast, we used EMFAC 2017 historical data, not forecast data, and we used distinct periods of calendar years for the low and high cases and averaged for the mid case.

While this captured a range of possible retirement outcomes, it fails to capture effects of the truck rules on used trucks and new purchases, which are expected to be high for 2022 and 2023. Next slide, please.

Here are the IEPR 2019 and 2020 patterns of retirement. Pretty constant for the 2019 forecast, but peaks in the IEPR 2020 forecast due to Covid and the '22 and '23 implementation of the truck rules. Also retirements gradually increase from 2024 on.

For IEPR 2019, the differences between low and high cases reflect both different growth rates in earlier years and different retirement schemes. However, for 2020 this difference is due to the growth rates only, since we're using the same retirement scheme in the three cases. Next slide, please.

New trucks purchased have a similar pattern, small changes for IEPR 2019 and -- from year to year -- and large variation in IEPR 2020. While lots of trucks retire in 2020, few are purchased due to Covid, and most of these were in the pipeline before March. Very large purchases in '22 and '23. And again gradual increase from 2024.

And the nerd in me needs to point out the higher mid case purchases in 2023. This is affected by the gap in purchases between the mid and high cases in the couple of years before that. So mid is catching up. Next slide, please.

Here imports and purchases of used trucks absent in 2020 but spiking in 2021 and to a lesser extent -- I'm sorry. Spiking in 2021 and 2023. Since EMFAC 2017 preceded Covid, we have decreased the number of used imports in EMFAC to reflect this strong used truck market, hence more expensive used trucks, which would make a new truck more attractive. The next slide, please. Thanks.

Yeah. The mouthful Hybrid and Zero Emission Truck and Bus Voucher Incentive Project, as usually called HVIP for obvious reasons. I remember former Director Rob Ogelsby referring to the AB8 program as aardvark for the same reason. So HVIP has evolved, now focusing on ZEV trucks and buses. In IEPR 2019, we varied the incentive level between the cases, but using a single case for incentives allows us to see changes between cases due to the other factors more clearly. So now we're using the percentage of the incremental cost of ZEVs. That's -- or of alternative fuel vehicles, all -- that's the difference -- the incremental cost is the difference between the price of the ZEV truck, let's say, and the default gasoline or diesel truck, depending upon what truck class you're in.

From 2018 to 2019 HVIP records, we averaged the percentage of the incremental price for the most common class, which turns out to be 86.5 percent in class 6, I believe. So compared to IEPR 2019, this makes shares of ZEVs higher in the low-electricity-demand case and lower in the high case. With the mid case, almost the same, as you will see. Next slide, please.

We changed the basis of commodity growth. The Freight Analysis Framework Forecast from the Federal Highway Administration show that the trends follow the patterns of Moody's Transportation and Distribution County-Based Forecast. All the granular origin, destination, and commodity volumes stay in their original proportions, but now they sum to reflect Moody's. To get high and low cases, we have mapped the transportation and distribution county forecast to the high and low using the ratio of spread in the three Moody's County GSP cases. Next slide, please.

The dotted lines show an index of goods movement from FAF captured in IEPR 2019 and solid lines for IEPR 2020. Note the Y axis doesn't start from zero, so we see Covid is expected to reduce goods movement in 2020 by about 10 percent, much less than personal travel, which squares well with other estimates. We're not moving around but we're still buying stuff. Also note that even the low case exceeds its indexed value for IEPR 2019 by 2029. The high case crosses in 2023 and it's nearly 10 percent higher in 2030 than IEPR 2019. The mid case crosses in 2024 and is maybe eight percent higher in 2020 -- in 2030 than it was for IEPR 2019. Next slide, please.

Here's our summary table for inputs by case. We'll pass over inputs that are the same in the three cases, or skip down to our hydrogen price, in blue, follows our commercial fuel price rates for low and mid cases. But for the high case, as in IEPR 2019, we assume a price applicable to dedicated fleets which move over fixed routes, point A to point B, or return to a home base each day. Retail hydrogen is expensive in part because the stations are under utilized. So the assumption here is that dedicated fleets will right size their station to meet the known demand of their truck -- of their truck fleet.

Electricity and other fuel prices follow the pattern in our other models, with high prices for alternative fuels in the low case and low prices in the high case. Truck battery pack prices follow the light-duty pattern of prices, but they're increased by 30 percent due to the demanding power ratings and more robust builds due to the demanding truck drive cycles.

Fuel economy follows a similar pattern, better for alternative fuels in the high case and worse in the low case, and the reverse for conventional fuels. Note that the truck fuel economy follows the NHTSA EPA fuel-efficiency standards that are still in place. Truth be told, the difference between cases for some truck classes in fuel economy are small to nil as the NHTSA EPA fuel-efficiency standards are expected to drive all the cases.

One significant change this year is the assumption of what daily range a battery-electric truck can handle, 150 miles, up from 100 miles in IEPR 2019, reflecting recent advances in technology. Next slide, please.

Operating costs are the biggest driver of new truck fuel -- new truck purchases in our model, so here we can see how the relationship of ZEV fuels to conventional fuels, diesel specifically, varies between the three cases. In the green, low-demand case, electric cost per mile, that's light green, is the lowest, but due to an expected low diesel price, that's dark green, the cost per mile, is only slightly lower in 2030. Conditions are better for electric in the -- in the low case in IEPR 2019 -- actually I'm not so sure of that, so let's ignore that sentence.

The mid case in blue is similar, with the management of electric in 2030 being a bit greater. Only from 2022 on in the high case is hydrogen cost per mile, that's medium red, lower than diesel. And this is due to the dedicated fleet price kicking in when the class 8 fuel cell tractors -- or semis, not the farm tractor, are introduced. Also in the high case, the advantage of battery electric over diesel, again diesel dark, battery electric light. Next slide, please.

Watch out, here I switched the position of IEPR 2019 and 2020 values from the previous slides for no reason. Last year, the number of zero emission trucks and buses was really high and the low really low, but you can see the mid case in blue just crosses 80,000 in 2030. For IEPR 2020, the mid case ends up in the same place, just over 80,000. High and low, however, are clustered closer at about 90,000 and 70,000 in 2030. I for one find the similarity in the mid cases reassuring. Next slide, please.

Here we have the same data but with electric fuel and fuel cell stacked. IEPR 2019 high case had over 10,000 fuel cell tractors, but setbacks at Nikola pushed the date of introduction for these back a couple of years. Toyota and Hyundai fuel cell day cab tractors are coming along, so not all the eggs are in one basket here. The rate of growth for fuel cell tractors remains high, on the same curve, just pushed back a couple years. So big numbers are expected maybe two years later than they were in the previous forecast. Next slide, please.

Here is expected growth in electricity consumption by buses and trucks by utility. Edison and PG&E, the streamlined three-letter acronyms, account for about two-thirds of the total, which reaches about 1100 gigawatt hours by 2030. Next slide, please.

Here is the forecast of battery-electric truck stock for class 3. That's grossing 10,000 to 14,000 pounds, which our colleagues running EMFAC call LAHD2. Mid and high cases exceed 30,000 by 2030 and the growth of the low case suggests it's headed in the same direction. Slide 6 -- next slide, please, slide 16.

Turning to classes 4 and 5, we see a very similar pattern, despite being a different size, traveling a different number of miles per year, bearing different purchase and maintenance costs. Honest, I really didn't -- I didn't just copy the previous slide. Next slide, please.

The class 8 tractors by the three ZEV fuel types here. Battery electric shows the most growth in all three cases. Direct electric, the catenary tractor, the class 8 tractors that would serve the ports and railyards in the L.A. Basin grow more gradually later, but still show an increasing year-to-year growth that bodes well for the future. We also see the lowest is the hydrogen growth, but you can see the year-to-year increase in hydrogen toward the end is increasing. Next slide, please.

Now we turn to the Advanced Clean Trucks Regulation, requiring manufacturers to purchase or earn credits from ZEV or near ZEV medium- and heavy-duty trucks. Plug-in hybrids are eligible for credits based on all ZEV miles of range. In each year starting with 2024, all new trucks manufactured will count as deficits, including ZEVs and near ZEVs. A credit multiplier factor favors heavy-duty ZEVs over medium-duty starting with those over medium-duty. Manufacturers must maintain positive net credits in all years. And manufacturers of ZEVs only can sell their credits and sell credits. Credits can be used for five years from the truck's manufacturer but only once.

Some notable differences from our forecast are built into the Advanced Clean Trucks analysis. We consider all possible fuel types where the ACT comparison includes: Battery-electric, hydrogen, fuel cell, diesel, gasoline, and -- I believe in some cases -- low-NOx gas. So conventional gasoline and diesel hybrids, other compressed and liquified gas, E85 and propane count as deficits for Advanced Clean Truck that are included in our truck-choice model in the appropriate classes.

For truck classes, we have ZEV prices and fuel economy for our evaluated year. At the end of the day, our admitted high cases maintain net positive credits on a statewide basis. We don't have the ability to evaluate ACT for individual manufacturers, so statewide will do. Next slide, please.

Here we see credits accumulate from 2021 and deficits accumulate from 2024; for this reason, net credits in our mid case are lower in 2024 than 2023. Net credits toward 2030 are lower because ACT increases credits required to retire deficits by five percent per year in some classes. ZEV shares grow in all three of our cases, but the mid case ZEV shares do not grow at this five percent per year. So without introducing a minimum ZEV constraint in our model, advanced clean trucks worked. In other words, we achieve that compliance or success in net positive credits without a hardwired, forced purchase. Next year we'll see about that low case. Next slide, please.

So here the top of the chart defines the ACT classes. Note that classes 2-b, 7, and 8 straight trucks, and class 7 tractors are not part of this analysis. The bars represent forecast results. And the lines, the percent requirement for ZEV shares.

Looking at the broad ACT classes separately, we see our class 3, LHD2 trucks, produce an excess of credits and class 8 tractors keep pace, but our classes 4 and 5 and 6 are falling behind after 2027. Positive net credits are not required for every class since credits can be traded only for manufacturers across all their classes. Slide 21, please.

Here are the counts of net ACT credits by their classes. Class 3 shows a lot of credits earlier and peaks by 2028. The ACT class 48 straight trucks go under water in 2029. However, credits for this -- for the heavy tractor class are positive and on the rise as the forecast ends. Next slide, please.

So that ends this part of the presentation. Here is my contact information. And I want to acknowledge people on our team, Alex in particular, and also Jesse for VMT data, Aniss for general consulting, and Elizabeth for a lot of help with presentation. And now we'll move on to Alex Lonsdale who will talk about the development of the load models.

MS. RAITT: Actually --

MR. MCBRIDE: Oh, we're going to --

MS. RAITT: Actually -- this is -- this is Heather. This is Heather Raitt. Thank you so much, Bob, for that. Actually I think what we're going to do is go to see if the Commissioners have any questions.

MR. MCBRIDE: Oh, okay. Sorry.

MS. RAITT: So if, Aniss and Mark, if you could turn on your videos, and we'll see if the Commissioners have questions. Thank you.

COMMISSIONER MONAHAN: I do, but I don't want to -- I don't want to interrupt the Lead Commissioner for this.

LEAD COMMISSIONER MCALLISTER: Yes. Well, I just -- I want to acknowledge Commissioner Monahan, you, for leading this IEPR Update in its entirety. So I think, you know, certainly I oversee the forecast, but you have a lot invested in this whole process throughout 2020. And as Lead on Transportation, I think you're really in a better position to ask specific questions on this, so.

But I really appreciate the, I mean, massive amount of work that went behind this and really interesting to see the places where the Covid, you know the sort of overlay of Covid has affected the, particularly, EV forecasts, but in some ways really affected heavily, in other places not so much, so that's been kind of interesting to understand.

I don't have any specific questions. I'm pretty familiar with the rules and appreciate all the background information about how the data sources have changed and been updated, so thanks to Aniss and Mark and Bob. So I'll pass it on.

VICE CHAIR SCOTT: Yeah. I mean this is -- this is Janea. I just had an opportunity to join about 10 minutes ago, so I missed most of the presentation and don't have any questions yet, so happy to hear yours and maybe rip off some of those, potentially.

COMMISSIONER MONAHAN: Yeah. I'm guessing you would have, if you had been here, you would have a lot of questions with a lot of good commentary, Vice Chair Scott.

So, well, thanks, Aniss, Bob, Mark, and the whole team. Really I appreciate that you all have been kind of evaluating, I would say, the boundaries of transportation modeling and really trying to assess how zero-emission vehicles could penetrate the fleet. And I just have a few overarching comments before going into questions.

You know my commentary is really that it is -- we're modeling things -- you know we're trying to model a transition that has not yet occurred without a lot of background into figuring out how to do it.

So, for example, we do not know the impact of infrastructure. We know -- we can't quantify it. We know it's important. In fact, I would argue it's the second most important issue after vehicle price, is access to infrastructure, and yet we cannot model it. We don't know if we got, you know, chargers in every apartment building, what would that do to drive the demand for passenger vehicles.

And so I just want to emphasize that modeling can only take us so far, and we have to use sort of common sense for some of the policy solutions that need to drive our investments going forward. And, as I said, you know, we -- it's really hard to model. As we know, battery prices in particular are -- are falling fast. In the next five years we should have cost parity, in fact they should be cheaper from a vehicle perspective, let alone the total cost of ownership perspective on both light and heavy-duty for a lot of applications.

And there are some performance enhancements from electric. Anybody who drives electric, recognize that 0 to 30 torque is really fun, and there could be some safety enhancements from the low center of gravity that still needs to be evaluated. But, you know, we don't -- so we're trying to model a transition that has not yet occurred. And I just want to give the staff a lot of credit for being creative and exploring new ways to quantify this, but also to show some of the challenges that we're going to have as we move to a zero-emission vehicle future, we have to acknowledge like there are real historical precedents that we are trying to overcome and we are trying to accelerate the transition.

I just looked at the Bloomberg and Energy Finance data on greenhouse gas emissions for the U.S. and I thought it was fascinating. So they're anticipating a nine-percent drop in overall U.S. emissions. That's the biggest drop in emissions -- that's the biggest -- you know, our emissions are equal to now about what emissions were in 1983, just to give you a sense of how big it is, due to Covid. And the number one driver, transportation. They say transportation emissions are down 14 percent in the U.S.

And from the -- I eyeballed the data that you all had and I couldn't really -- it was hard to tell, but do we have a sense for overall energy use demand in both the light- and heavy-duty sector, what the fall is projected to be as a result of Covid?

MR. MCBRIDE: Well, I can say goods movement, it looks to be about 10 percent this year and maybe next year. And then it returns to somewhere like normal, about 20, 23, or '4.

COMMISSIONER MONAHAN: Um-hum. And, Aniss, what was your -- or, Mark, what -- could you tell for -- I couldn't tell from the graph, I was like, oh, what percentage is that.

MS. BAHREINIAN: I think when it comes to gasoline consumption for any sense, there is a projection of about 17 -- 14 to 17 percent drop for the 2020 forecast. For the 2020 consumption, it is less of this for diesel because of those two graphs that we showed, but we didn't measure total drop in consumption. But if you go back to the graph where we added up all of the different fuel types, the one that was in BTU unit, that graph shows the decline for 2020 in terms of BTUs, when we can convert that to percentages. So that's the only one that we show, but keep in mind that most of what the forecasting and the impact of Covid is through the impact of economic variables. So to the extent that income goes down or GSP goes down, then we can show some decline in that area. But -- and the actual impact as -- and the short-term impact, as was shown in Gordon's graph could be more significant than what we are projecting.

COMMISSIONER MONAHAN: Um-hum. Aniss, I had a question for you on vehicle sales, because you highlighted historically that there has been a drop in vehicle sales. So we had a peak in 2016, maybe as the post-recession kind of bump, but the vehicle projections going forward are pretty -- kind of steadily increasing, assuming population and economics drive that -- that. But I'm wondering, can you explain why there was the drop between 2016 to today and whether we may have a more complicated sort of relationship between vehicle sales and population going forward?

I know the next session is going to talk about -- I think it's going to talk about the impacts potentially of Lyft and Uber and other types of services that could be a -- of what the impact could be of those types of services kind of syphoning away BMP from personal car ownership?

MS. BAHREINIAN: Well, the decline in the new vehicle sales that you saw on the CNCA graph can be explained -- first of all, you saw that, for instance, that the 2008-2009 year it was increasing, showing the economic recovery. So it is very much correlated with the economic recovery, but also there is another factor: Once a lot of people are buying a new vehicle, it is usually a cyclical behavior. Like when you are buying it and you go say this year, you probably won't go into the market for another five years. Usually around the year six is when you start buying the vehicle again. So there is that cyclical year. So if a whole bunch of people are buying a lot of new vehicles in one year, then those people are going to get out of the new vehicle market and it is going to reduce the inevitable buy for another five years.

Now this behavior is different in different markets. For instance, in the rental market that five-, six-year time period is going down to, say, two or three years at the most. So in the rental market they turn over those vehicles quite fast, faster than all the other sectors. But in the residential sector, the rate is lower. In the commercial sector, they turn it -- the turn over is faster than the residential sector, and so on and so forth. So there are different rates, but overall you can see that once a whole bunch of people are buying new vehicles in one year or one short time period, then new vehicle sales is going to go down in subsequent years until it goes up again.

COMMISSIONER MONAHAN: I think I know the answer to this question, but just to make sure, did the modeling assume that the California Vehicle Standard, the ZEV mandate, and the Vehicle Greenhouse Gas Standards remained intact or did it have any slump due to the rollback by the federal administration of vehicle standards?

MS. BAHREINIAN: Well, one thing that we did include and we have, for instance, in the low case, what we did, we assumed that CAFE standards are going to be sort of retired in 2021 because of the changes that the federal administration did actually, but in the other cases that we have, like in the mid, high, and aggressive cases, we assume that those CAFE standards are going -- which is California's preference of course, they are going to stay in place, so we have different scenarios to reflect different situations.

COMMISSIONER MONAHAN: Interesting. And what -- I guess this is before NHTSA actually acted to -- because they did have an increase and took the modest 1.5 percent between 2021 and 2026.

MS. BAHREINIAN: Yes.

COMMISSIONER MONAHAN: So the low case is really sort of below this, even with what the rollback is.

MS. BAHREINIAN: Yes, yes.

COMMISSIONER MONAHAN: Okay, that's good to know. So presumably when -- now that we have a federal administration that believes in science and climate change, and is talking about working with California on standard setting, as California moves for a more aggressive ZEV mandated post 2025, that will be reflected in our modeling going forward?

MS. BAHREINIAN: Exactly, exactly.

COMMISSIONER MONAHAN: Okay.

MS. BAHREINIAN: And the reason for that, we also have a new survey that we conducted and completed in 2019. The climate forecast is being done and the results of our 2017 survey, but the 2019 survey, which is a newer survey, that shows the new customer preferences, that is going to be incorporated into 2021 forecast. So we have to make the model, make it ready for that year, so.

COMMISSIONER MONAHAN: So I want to turn to the question for Bob, and then I'll let other folks state. So -- excuse me.

I was listening that, I was interested in that fuel cost per mile which showed the electric is far lower than everything else and that -- you know, but really it's still cost of ownership. Do we have a total cost of ownership applied?

And, you know, I was really -- just one more comment and then you could think about it while I -- and I want to -- at our IEPR Workshop for the transportation section of the IEPR, we heard from one transit district that they're actually paying negative fuel prices because of the LDV effect, that they're making money per mile on fuel. So a lot of it varies depending on your BMT and the credits that you're going to get for electrifying.

Do we have any -- you know, do any of our -- do we do any of these cases where we would go down to a negative pricing, like what at least one transit district is experiencing?

MR. MCBRIDE: I don't think we see negative prices, but we do include the LCFS credit value for the -- for the freight and truck base. I -- I did cite --

COMMISSIONER MONAHAN: I mean it occurred to me that so much is based on what you're paying for electricity, right, and that's --

MR. MCBRIDE: Right, right.

COMMISSIONER MONAHAN: -- going to vary a lot across -- and this is one of these important nuances that we don't get into and maybe it's a case that we could think about for the future is, you know, if you're able to secure, say, I want to say 10 to 15 cents per kilowatt hour, electricity by charging at the right time of day and having that kind of relationship with the utility where you're really optimizing the vehicle grid integration asset and then getting the LCFS benefit. It could just show -- and I think this is where we want to go in the future, is showing how to use transportation electrification as a boon for the grid, how to integrate renewable energy, you know, how to get us to the win-win-win, right, where we are integrating renewable energy, so we're helping the grid get cleaner, we're cutting transportation pollution, and we're helping the consumer or the end-user to save money. So that's the win-win-win we're looking for and it really -- I think we need to have vehicle grid integration be a key part of that, so thinking through in the future how do we more and more model that to help end-users make good decisions?

MS. BAHREINIAN: I should also add that when it comes to the transit buses, which was I guess related to the question that you just asked, hopefully all of those are going to be reflected in the transit agencies' plans, approaches to purchase new buses, and our colleague Ysbrand van der Werf is going to take a look at those plans by different transit agencies. And to that extent, then he is going to incorporate those new plans into the overall transit model.

COMMISSIONER MONAHAN: Um-hum, that's great. Oh, I have one more last comment -- last comment, which is I think the THAS numbers are -- I think we think about more about what the -- what the THAS (phonetic) administration is going to be, as the battery-recharge time goes down, the battery performance -- you get to increase the price. You know, having both an internal combustion and a battery-electric vehicle, you know, integrates. It's expensive. So I just wonder if that is something we should be thinking more about, is like what really is going to be that rational THAS share as the battery performance improves and especially the recharge time, I think it's a critical factor. So even more food for thought for the future, nothing that you have to respond to now.

MS. BAHREINIAN: So we appreciate that. For next year, we have an agreement, a contract with NREL and they will be generating our light-duty -- we call -- attribute forecast and they will be incorporating all these different changes that are happening in the market, but overall what I can say is that based on the survey that we have conducted, consumers have higher preferences for ZEV. And our forecast actually has shown for a few of the last IEPRs, and we were almost the only agency that was projecting a higher share of ZEVs converted to ZHEVs. And back in 2017 the only other entity that was doing the same thing was actually Bloomberg. Everybody else was forecasting the same amount of and the same number of PHEVs and ZEVs. We think it is ZEV that is going to win the day.

COMMISSIONER MONAHAN: Yes. Well, I've got to say Bloomberg was correct in the -- in their -- if you look at the history, they were correct.

All right, but I know I've taken more than my share of time, so I'm popping off. Thanks to all of you.

MR. PALMERE: Thank you, Commissioner.

MS. RAITT: All right. This is Heather Raitt.

Other Commissioners? I'm not hearing any other questions, so thank you for that discussion.

Thank you, Bob, Aniss, and Mark, so much for your presentations.

And it looks like we do not have any Zoom questions right now, so we can go ahead and move on to the next portion of this morning, on Exploratory Transportation

Scenarios. And so our first speaker is Alex Lonsdale. And he'll start the conversation for us and Alex is the Lead Analyst in the Energy Commission's Assessments Division, responsible for EV charging load shapes.

So go ahead, Alex.

MR. LONSDALE: Thank you.

Good morning, Commissioners, stakeholders, and Zoom participants. I'd like to thank you again for attending today's IEPR Workshop. Today's presentation will focus on load shape forecast updates in the exploratory load shape scenarios. Next slide.

So the presentation outline. It's broken up into three segments. First I'm going to provide an overview of our EV infrastructure load model. Second, I will go over updates that were made to the EV infrastructure load model. These updates affect the transportation load shapes which are included in the hourly electricity demand forecast.

The last section of this presentation will focus on the exploratory scenarios. Note that the exploratory load shape scenarios are separate, in the low-, mid-, and high-demand cases, and do not play a role in the California Early Electricity Demand Forecast. Next slide.

So now we will begin with the EV Infrastructure Load Model Overview. Next slide.

So what is the EV Infrastructure Load Model and how do we integrate it into our forecasting? The EV Infrastructure Load Model was constructed by ADM Associates to integrate plug-in electric vehicle charging load shapes into the hourly California Energy Demand Forecast. It is a top-down model that disaggregates the annual transportation electricity demand forecast according to observed or assumed charge behavior. The model essentially assimilates how residential and commercial transportation sectors may respond to time-of-use rates. Next slide.

So here we have a model schematic, adopted from the California Investor Owned Utility Electricity Load Shapes Report, prepared by ADM Associates. There are three input categories indicated by the dark blue arrows. At the top of the schematic in red we have the economic inputs. Economic inputs include price elasticity and demand, in this case, a change in demand relative to the change in price of electricity; Residential Time-of-Use Rate Participation Forecasts; and the last three inputs, prices, rates, and seasons, which make up the time-of-use rate input for each of the IOUs that we model. This includes PG&E, SCE, and SDG&E.

Moving in a clockwise direction, the next category of inputs are the Transportation Electricity Forecast inputs for the vehicle types that we model. This includes LDV Energy, segmented by commercial and residential sectors;

neighborhood electric vehicles; class 3 to 6 medium-duty vehicles; class 7 and 8 heavy-duty vehicles; and buses.

The last set of inputs in the orange are the base load shape inputs. The base load shape inputs charging profiles for each energy category that we model. The personal vehicle charging location shares input is used to allocate a portion of annual personal vehicle electricity consumption to the commercial sector to account for destination or workplace charging. Next slide.

Modeling demand shift. The economic inputs to the EV infrastructure load model are used to determine how the hourly electricity demand may shift due to impacts of time-of-use rates. In short, the adjustment factors determined from this equation shown may change the percent of daily electricity consumption that occurs during each hour. The adjustment equation that was developed for the model is shown here. Note that for commercial adjustment factors, we do not include the TOU rate percent variable.

Adjustment -- or the adjustment factor, A sub *h*, is defined as follows. It's a product of the TOU rate percentage, again for only residential customers. PR sub *h*, the price ratio, defined as the price prevailing at hour, *h*, divided by the lowest available price for the given day, at the same location. And then *e*, again is the Elasticity Factor. In summary, this equation is the main driver for notable shifts in demand with respect to our transportation load shapes, specific to each IOU territory. Next slide.

So that concludes our brief overview of the EV Infrastructure Load Model. I will now move on to the PEV Charging Load Shape Forecast Updates.

So there are a series of model input updates, and this applies to the low, mid, and high scenarios. The residential time-of-use rate participation forecast has been updated. In general, the residential time-of-use rate participation has increased across all forecast years.

Time-of-use rates. The 2020 time-of-use rate input includes more current rates available from SCE, SDG&E, and PG&E. Recall that time-of-use rates, specifically the peak to off-peak price ratio shown in the Adjustment Factor Equation, is an important metric with respect to determining the magnitude of load shift in the EV Infrastructure Load Model. Third, we decreased the price elasticity of demand for both commercial and residential sectors.

Next, the personal destination load shape was updated. That accounts for level 2 workplace, level 2 destination, DC Fast, and roadtrip charging. This update of the personal destination load shape attempts to characterize the different charging options when personal vehicles are not charged at home. In addition, this update is consistent with the profile used to determine the amount of annual personal vehicle electricity that is consumed at public-charging locations.

Last but not least, we updated the personal-vehicle charging location shares, which aligns with EVI-Pro simulation data. Previously these values were transcribed from the 2017 to 2025 EV Infrastructure Projections Report. Next slide.

So now we are going to be comparing IEPR 2019 and IEPR 2020 load shapes for the aggregated LDV category and MD-HD category. Note that these comparisons are for average summer weekdays in 2030, and load is represented as a percent of daily load. The IEPR 2020 load shapes are the dark blue lines and the IEPR 2019 load shapes are the dashed light blue lines. A general note is that there is less load shifting during the on-peak period for the IEPR Update.

Decreased load shifting is a result of updated rate inputs and how the EV Infrastructure Load Model calculates load adjustments. In order to better capture load shifting specific to time of use, that plans to continue improving how this model responds to these economic inputs. As shown, hourly load during the on-peak period hours, which is defined as hours 17 to 21 on the graph, increased from about.6 to around 2.3 percent for LDV and approximately from 1.8 percent to 2.6 percent for MD-HD. Next slide.

So here we are comparing load shapes for Southern

California Edison. And note that the model is very sensitive to the IEPR 2019 commercial time-of-use rate as shown by the IEPR 2019 MD-HD load shape. Again, currently our model treats load shift across -- the same across all IOUs. If the on-peak to off-peak period of a price ratio is large, the model is going to be sensitive and adjustments are increased.

As shown, hourly load during the peak hours, again hours 17 to 21, increased for about 1.3 percent of daily load for any given hour to around 2.3 percent for LDV, and approximately 1.4 percent to 4 percent for MD-HD. And noted that last year we used the EVTOU 8 rate and had a price ratio for the on-peak to off-peak period of 4, which is now 2.9 in the updated rates. Thus, there is much less load-shifting end result. Next slide.

So, lastly, we compare the San Diego Gas & Electric load shapes. Again this is for an average summer weekday in calendar year 2030. As shown, hourly load during the on-peak period hours increased only slightly for LDV here, from 2.8 percent to 3.5 percent for LDV; and actually slightly decreased from 4.1 percent to 3.9 percent for medium and heavy-duty. A decrease for the medium and heavy-duty load shape has to do with the split of class 3 to 6, class 7 and 8, and bus regional energy forecast, which wastes the resulting aggregated load shape that we generate.

Next slide.

So that concludes the second segment of my presentation. And now I'll be discussing the exploratory scenarios of plug-in electric vehicle charging load shapes. Next slide.

So while the exploratory scenarios were developed outside of the EV Infrastructure Load Model, they do share many of the same data inputs. Leveraging the EV Infrastructure Model inputs allowed staff to make consistent modeling assumptions with respect to the low, mid, and high-demand cases.

Again, these are what-if scenarios developed in addition to the low, mid, and high-case forecast. They're intended to estimate the impacts of proposed programs, policies, or other relevant questions that are outside the scope of our adopted forecast. These scenarios were developed outside of the EV Infrastructure Load Model and are not dependent on the time-of-use rates.

The GHG scenario explores the statewide impact on the grid if EV charging was managed to minimize GHG emissions. The worst case scenario explores the impact on the CAISO system if the majority of EV charging occurs during peak hours. Next slide.

So now I will begin with the discussion on the GHG-reduction scenario. First, I'd like to thank CEC staff from the Planning and Modeling Unit and the Supply Analysis Office for performing the work and providing the data necessary to make this scenario analysis possible.

The following table shows projected hourly system average CO_2 emission intensity for calendar year 2030, and is based on the adopted IEPR 2019 mid case. These factors are determined by simulating the width and why of electric sector generation and fuel use on an hourly basis.

Going in the X direction, as indicated by the arrow, we have hour of day, and then in the Y direction, the month of the year. A heat map is applied to show off the grid system's emission intensity in 2030, is expected to vary with time of day. In general, the nighttime and early morning hours have greater emission intensity factors, shown in the red and orange color, typically since less renewable energy generation is expected to be online during these hours. In contrast, the grid system is expected to be less carbon intense during the afternoon when renewables such as solar are expected to generate more electricity.

So since emission intensity is less during the day, one approach to reducing transportation-related GHG emissions would be to install more workplace public destination chargers. With increased public charging options, EV owners have increased opportunity to charge mid-day and take advantage of renewable generation. Next slide.

The GHG Scenario: Flexible Vehicle Categories. As noted earlier, the exploratory scenarios leverage model inputs from the EV Infrastructure Load Model to make scenario comparisons possible and to make the same assumptions regarding daily electricity consumption for each model vehicle category. For the GHG scenario, flexible vehicle electricity was applied to the GHG reduction load shape, which will be shown on the next slide. The inflexible vehicle category's charged profile is determined from the base loadshift input, used in the EV Infrastructure Load Model. Again I would like to highlight that we do ignore the effect of time-of-use rates here. Next slide.

The GHG Scenario: Flexible Summer Weekday Profile for 2030. So the following charge has two profiles. The first one, in the blue, is the hourly flexible charge profile for an average summer weekday in 2030. Note that the load shape values are presented in terms of percent of daily load. The gray dash profile is the average emission intensity factors for a summer weekday in 2030. And it's presented on the secondary Y axes in metric tons of CO_2 per megawatt. Here we see that more load is applied during hours of low-emission intensity, while high-emission intensity factors results in less load for the given hour. Next slide.

So here we have a table with two measures. We're measuring system peak contribution megawatts. This is for the average summer weekday in 2030, shown in the chart below, as well as the annual GHG emissions and metric tons of CO_2. Note that this is annual GHG emissions from charging. The forecast at mid-case peak contributions, 1,384 megawatts. That is during hour 19 of the day. For the GHG reduction scenario, peak contribution is 2,046 megawatts.

You will note that the annual GHG emissions from charging in the mid-case is about 1.7 million metric tons of CO_2, whereas the GHG-reduction scenario has about 1.3 million metric tons of CO_2, a total reduction of about 23 percent.

The forecast at mid-case system peak contribution is lower because the EV Infrastructure Load Model was built to shift load, according to time-of-use rates. Since electricity costs the most during non-peak period in current rate structures, load is -- load shift primarily occurs during these hours. Next slide.

So that concludes the discussion of the GHG reduction scenario. I will now transition to the worst-case scenario. I would like to emphasize that we do not think that this is a realistic scenario as it assumes all EVs are charging at the same time and during the on-peak period. This is not a likely scenario as time-of-use rates incurred through nighttime off-peak charging when electricity prices are the lowest.

So as you can see here we developed two profiles.

Note that we have a double axes chart here. The Exploratory Charging Profile, applied to the forecast of daily electricity consumption from all vehicle categories, is shown as a light blue dash profile. The dark blue profile shows how adding transportation load according to the Exploratory Profile would affect the CAISO system load.

Next, the CAISO high-low transportation load shape is shown by the gray dash line, this is generated by the EV Infrastructure Load Model. As we can see from the graph, there is significantly less on-peak period charging when comparing the charge profiles. The dark gray line represents the CAISO high-low system profile. From the charts, from both charts, we can see that the transportation load, if left unmanaged, could significantly impact electricity demand.

The Exploratory Profile in Profile -- or in case 1 shows that we would increase the on-peak period demand during hour 19 by 5,295 megawatts in calendar year 2030, on a typical summer weekday. And Profile 2 would increase the peak demand by 8,501 megawatts in 2030. Next slide.

So there are some key takeaways here. These scenarios highlight the importance of time-of-use rates or other strategies to discourage PEV owners from charging during the peak system hours. When developing load-shifting strategies to address climate change, it's important to consider both grid conditions and GHG emission intensity factors. Next slide.

Thank you. And I've also included a link to ADM's complete documentation for our EV Infrastructure Load Model, located in Chapter 10 of the Report.

And I believe now we're going to actually take questions, if I'm not mistaken.

MS. RAITT: That's right. Thank you, Alex.

LEAD COMMISSIONER MCALLISTER: Let's see here. So thank you for that, Alex, that's great.

I just have a couple. This makes a lot of intuitive sense to me and I really appreciate your working with the utilities and the assessments divisions, the cross divisions to inform this work really exactly how we need to be approaching this.

And I wanted to also just point out that, you know, load management standards have a lot of potential to help push this conversation in terms of doing what you suggest, which is managing this particular set of loads in a way that's intentional and in line with state policy and across agencies together with the PUC and the ratemaking realm, really enabling tools to do that management at a reasonable cost.

So I did have one question -- or two questions. One was about the behavioral model, sort of the response time of use. You know there's been a lot of work in different realms about this, looking, taking large datasets from different consumers and figuring out what the behavioral response to different rate regimes and pricing schemes actually is. I wonder how much of that you've been able to do in this realm and kind of just suggest perhaps that EPIC, this might be a nice place for some R and D to look at how behavioral response actually -- to understand behavioral response in the various transportation sectors actually might look like.

MR. LONSDALE: Right. So one of the main reports that we've looked at is the Nexant Report from San Diego Gas & Electric and they did a study on the effects of time-of-use rates and actually looked at it a more granular level looking at PEV owners and nonPEV owners that actually own electric vehicles, and before they adopted the time-of-use rate and after they adopted a time-of-use rate, what's the demand shift relative to the price of electricity. And they kind of did a study on the price elasticity of demand and how responsive people were to the change in price. And it reflected a range of price elasticities for both cross price elasticity and own price elasticity. From price elasticity, it fell between the range of.3 and.5, which actually is kind of where our model falls for price elasticity demand.

But we're kind of continuing the process of updating. The equation that I showed prior to the adjustment factors is kind of the first stab at following demand shifts and we're kind of continually seeing a -- we've done a sensitivity analysis on this equation here and how our model actually adjusts our load profiles from these adjustment factors, but also just how it's actually renormalizing across the entire year after we applied these adjustment factors. And Nick Fugate has actually provided some directions for updating the models and kind of how we can go in the direction of just doing a better job in modeling these demand shifts.

LEAD COMMISSIONER MCALLISTER: Thanks a lot. It's funny that the work you just described sent me back to my own Ph.D. which was about consumption pattern response to the adoption of PEV itself, right, that people change their energy-use patterns after they get PEV. And at that time I actually had to -- there were so few EVs out there, but there were a few, that I had to actually try to identify them and screen them out of my analysis so they didn't pollute my analysis. And now there are so many of them that obviously we need to, you know, treat them as a segment of this question, right, so I think that's really --

MR. LONSDALE: Definitely.

LEAD COMMISSIONER MCALLISTER: That's great.

And that's a good segue to my second question which is about what do you hope to achieve with the data that we're talking about getting in the update of the data regs? Because I think that sort of granular data has a lot of potential. I'm interested in sort of how you're thinking about that helping this analysis.

MR. LONSDALE: Yeah, definitely that's a great question. So for our charge profiles or our base load shape input, those were developed by ADM back in, I believe, 2018. And there has definitely been a lot of advancements in charging behavior and vehicle technology since then, even with Teslas and all the other companies that are coming out with new technologies.

You know we've got a lot of data coming in and we're kind of mapping out this next month sort of what's our trajectory in terms of updating our charge profiles, do we get more granular with our vehicle categories. Because, as I showed, we aggregate sort of the medium- and heavy-duty space. And as well as the light-duty vehicle space, we're aggregating the classes into the total annual electricity consumption.

So we've -- another question that's come about, a lot of people have been asking about is you know we have this interface with EVI-Pro. We've got EV infrastructure projections tools and that STB is developed. And kind of people keep asking about the interface between their charging profiles and load shapes and ours, and we're continually trying to synergize between these two model constructs while also taking advantage of the fact that we have a plethora of potentially metered data coming in where we can utilize that for the LDV residential space to really improve our modeling and improving our charge profiles that we apply to these models.

LEAD COMMISSIONER MCALLISTER: Great. So, yeah, that definitely is worth some further discussions as we move forward with that regulation.

MR. LONSDALE: Certainly.

LEAD COMMISSIONER MCALLISTER: And, yeah, into IEPR for next year, so really thanks. Thanks a lot.

I'll pass it off to Vice Chair Scott and Commissioner Monahan.

VICE CHAIR SCOTT: Hi. Thanks, Alex, for the excellent presentation. I am really, really happy and cheered to see that we've got this increasing sophistication that we're adding into our PEV analysis, so I want to thank you and the team for that. As you guys know, it's incredibly important, especially as we continue to add more and more and more plug-in electric vehicles to our grid. So thank you very much for that.

One thought that I had as we were going through your slides, you mentioned that we had the datasets I think from PG&E, SCE, and SDG&E, we may want to consider including SMUD and LADWP if we can in the next round. I think between those five we'll have a pretty big chunk of the state included in our analysis.

MR. LONSDALE: Certainly. I think that's been a discussion and I think Heidi's actually pointed out to me that we should be including that in the next round of our forecasts as well, so I think that's definitely --

VICE CHAIR SCOTT: Um-hum, yeah.

MR. LONSDALE: -- the direction we're heading in.

VICE CHAIR SCOTT: Awesome. I think that would be great. And then this question may not be for you, but I was reminded of it as you were talking and I'm so sorry that I missed the first part of the Workshop, one of the things that I wanted us to consider as we're doing these more sophisticated analyses on the electric vehicles is the time-to-charger analysis that we're using or the metrics that goes along with that, --

MR. LONSDALE: Yes.

VICE CHAIR SCOTT: -- and how to capture that. And the reason that I say that is before I think we had something that was maybe a couple of hours -- not a couple of hours -- it was 10 to 15 minutes to get to a charger. But the point that I was making with the electric vehicles is that the light duty, you may be parking it at work or at home, which are places you were already going, so there's not really time to charger in that same way, as you would think about with the hydrogen fuel cell, for example, where you have to drive from where it is that you are to the fueling station. And so kind of thinking through how we capture some of those metrics as they change because of just the nature of the plug-in electric vehicles. So that may not be for you specifically but just --

MR. LONSDALE: Yeah.

VICE CHAIR SCOTT: -- kind of a broader thought as we increase the sophistication of our analyses here.

And then one other thought which also might be a little broader than what you are talking about, but I get so excited to see these scenarios and the best case scenario -- and I don't think that's quite what you called it -- and then the worst case scenario, but that gives decisionmakers and policymakers a lot of really data-rich environments with which to kind of think through policies and decisions that we're wanting to make. And so one thing I was thinking is, you know, with Governor Newsom's executive order for all vehicles to be electric by 2035, one of the things that we could do similar to the analysis that you showed with CAISO that had kind of that peak at, I think it was, 8500 megawatts, which is a lot --

MR. LONSDALE: Yeah.

VICE CHAIR SCOTT: -- for not using time-of-use rates, but is what does this look for electricity demand, right. If we have an increasingly electrified fleet between now and 2035, what does that look like for electricity demand. Our fuels team can look at what does that look like for hydrogen demand. And we can even probably go back and think through where we think some of the pinch points in our system are going to be as we try to make that transition.

So, anyway, this is just a really long way to say that I'm excited to see these sophisticated scenarios and analysis that you have presented to us today. So thank you for that.

MR. LONSDALE: Yeah. Thank you very much.

COMMISSIONER MONAHAN: I'm the last, hopefully I will end with enough time for us to have lunch, so I really appreciate the comments by Vice Chair Scott and Andrew -- Commissioner McAllister. Excuse me. And I just had a few more questions for you. I think they're pretty -- they're softballs.

But, I wonder, do we have -- you have the light-duty GHG case, do we have a worst case GHG? I didn't see, I just saw the peak but not GHG implications of that.

MR. LONSDALE: Yeah, the --

COMMISSIONER MONAHAN: Do you have that data?

MR. LONSDALE: So we didn't actually do a GHG determining calculation on the worst case scenario. I was more focused on the system peak contributions and the effects for the CAISO system. Where is the other scenario, the GHG scenario was more focused on actually calculating the GHG reductions from the total year. So the GHG reduction scenario we actually developed an 8760 profile set, dataset for load shapes. Whereas the worst case scenario was a smaller dataset example to focus on the peak effects for just a summer weekday, so it's a smaller dataset sample and actually doesn't run against the entire 8760 emission intensity factors.

COMMISSIONER MONAHAN: Got it, okay. I'm wondering, I want to build on something that Commissioner McAllister suggested and actually it relates to Vice Chair Scott's profile -- I mean her portfolio on R and D investments, is that I mean I think we have some good data on nighttime TOU pricing behavior. We don't have, at least my sense is we don't have good data on when we're asking sort of a more complicated charging profile. I mean, you know, where we want charging to occur in the middle of the day when we have a lot of renewable solar energy mostly that we're curtailing. And that's where I feel like we have a lot of data gaps. And I'm just curious about your sense, do you think that's correct or do you feel like we also have the data?

I mean I've just seen the BMW Charge Forward, just a few like kind of small --

MR. LONSDALE: Small.

COMMISSIONER MONAHAN: -- scale and they don't really give us a lot of data. And what's your sense of that?

MR. LONSDALE: Yeah. I mean the Charge Forward path and like sort of the BGI space as well, we're trying to -- they're kind of small pilot programs right now. There are small datasets there. In terms of, you know, like a plethora or a large dataset for mid-day charging with DER response and BGI technology, we don't have a large -- I haven't seen a lot of data there. We've hunt and pecked around a little bit. It's definitely something we're trying to explore further on the 2021 IEPR Update, try to like pinpoint some more datasets. But as of right now, like you're saying, I found -- looked through the Charge Forward datasets and a few others, but there's not a lot of data on the mid-day charging and sort of the DER response.

COMMISSIONER MONAHAN: Yeah. We know it's good, but we don't know how good.

MR. LONSDALE: Right.

COMMISSIONER MONAHAN: We know how to set the right incentive to create that behavior with stuff like we'll put a charger at a workplace, so folks can do it automatically. So that seems -- I mean, yeah, whatever works, but let's get some data --

MR. LONSDALE: Right.

COMMISSIONER MONAHAN: -- to support our decision making instead of just intuition. I know the Chair calls -- always says, which I have actually quoted him on this, like we want an EV happy hour where we're plugging in at the right time of day and --

MR. LONSDALE: Yeah.

COMMISSIONER MONAHAN: -- using up on solar, but how do we set the right policy to make that happen, I think that's the challenge for us.

MR. LONSDALE: Definitely.

LEAD COMMISSIONER MCALLISTER: Can I jump in on that actually? You mention the happy hour, and I was just actually -- this is a little bit out of left field, but I thought it was really interesting, actually we do a fair amount of international collaboration. And I was on a call recently with the state of Karnataka in India, and they actually have that for agricultural pumping. They get free electricity for nighttime hours, for multiple hours of the night. And they're going to move that -- they're getting so much PV that they're actually moving that to the day.

COMMISSIONER MONAHAN: Yeah.

LEAD COMMISSIONER MCALLISTER: The farmers are ecstatic about it because they don't have to get up in the middle of the night and turn their pumps on and off. And --

COMMISSIONER MONAHAN: That's cool.

LEAD COMMISSIONER MCALLISTER: And it's automatable and everything. So, anyway, there are -- you know, there are jurisdictions that we can learn from on this stuff as we get a lot of --

COMMISSIONER MONAHAN: Yeah.

LEAD COMMISSIONER MCALLISTER: -- really inexpensive renewables. Anyway, I thought --

COMMISSIONER MONAHAN: Yeah.

LEAD COMMISSIONER MCALLISTER: -- that was worth suggesting, but thanks.

COMMISSIONER MONAHAN: That's fascinating. Well, and I comment on that too is that I thought the heavy-duty data was fascinating. This is a place where I just think, wow, you know, businesses are still focused on the bottom line, that we could have an opportunity to electrify transportation just based on the lower price of electricity. If the signals are correct, right? There's demand charges and there's need for fleets that may -- they may not always be able to charge at optimal times from the grid, but if we could set the right incentives for that, that's another place where I feel like we have a dearth of information about how to create the right incentive for heavy-duty charging.

And some of the data coming out of our AB21, 27 and it will be a model in the IEPR as well is that, you know, if you look across the state, we have these diverse heavy-duty fleets. And each of these vehicle cases has very specific charging behaviors and patterns that are quite diverse. And so when you look at like the Central Valley and ag equipment being electrified, which Commissioner McAllister said about the pumps hear, is that there is going to be all these different charging behaviors based on the needs of the fleet. And I think there are just like a lot of analysis we can do around the grid impacts of those and how to set the right policies so that heavy-duty vehicles are charged at the right time.

And I'm getting pinged by Heather to get off. Alex, we could go on all day.

MR. LONSDALE: We could, we could.

COMMISSIONER MONAHAN: Thank you very much for the modeling. It was really exciting, new territory that you're moving forward with that, so thank you.

MR. LONSDALE: Thank you, Commissioners. I really appreciate your response.

MS. RAITT: Thank you, Commissioners.

Thank you, Alex.

Sorry to be the bad guy and have to cut off discussion.

MR. LONSDALE: Okay.

MS. RAITT: But we do need to hear from another presentation from Bob McBride.

So, thank you, Bob, can you go ahead and get started? Thanks.

MR. MCBRIDE: Start video. Hello again. Are you hearing an echo? Does anybody hear --

MS. RAITT: I don't remember an echo. You sound good to us.

MR. MCBRIDE: Okay. Ignore myself.

Hello again. This presentation describes the Exploratory Scenario on Impacts Additional Medium- and Heavy-Duty ZEV Chart Populations to Meet the Federal Ozone Standard in the South Coast Air Basin in 2031.

The assessment has two parts. The first is this presentation that takes us to electricity consumption, followed by Alex's presentation that transfers and sees results to impact on electric load -- we may have already covered that, but I'm not sure. Next slide, please.

We call it the attainment scenario. We assess the increase in electricity consumption from the number of plug-in trucks needed to reduce the internal combustion emissions and meet the 2031 Ozone Standard. First I'll provide some background and describe the need for this scenario. Then I'll describe how we use three things: One, a basin-specific dataset associated with the ARB's spreadsheet, META, an analysis tool to support the Air B Mobile Source Strategy; two, one of CEC's IEPR Transportation Energy Demand Forecast cases; and, three, a new closely-related scenario, the model used in the IEPR forecast. Finally, I'll describe results. At the end of the slide deck is an appendix on an alternative scenario that you can look at afterwards. Next slide, please.

Various sources emit oxides of nitrogen, or NOx, on a low-level atmospheric precursor to ozone. California has made great progress over decades in reducing NOx, but to meet the Federal Ozone Standard intended to reduce health effects, more reductions are needed. The Mobile Source Strategy calls for a 57-percent reduction of NOx emission from the current base line -- that's the dotted line -- in 2031. Next slide, please.

Of all the sources of NOx, medium and heavy vehicles comprise 32 percent of emissions, essentially a third. Heavy-duty vehicles alone are 26 percent. Next slide, please.

South Coast AQMD is pursuing the replacement of internal combustion engines with zero-emission drive vehicles in the South Coast Air Basin, the lion's share of South Coast AQMD. Heavy-duty tractors, again semis, not farm equipment, are targeted as the largest on-road generators.

The Mobile Source Strategy target for ZEV tractors is more than double the CEC mid-case forecast. Some classes are closer to their target, as we'll see. If the strategy is pursued for the South Coast Basin or implemented, utilities in the region will have to plan for the electricity supply and capacity required. Next slide.

CARB and South Coast AQMD staff shared META results for South Coast Air Basin for 2031. In the META tool, internal combustion trucks with the greatest NOx emissions are identified and replaced with a sufficient number of zero-emission trucks each year to meet the Ozone Standard in 2031. CEC staff started with the mid-case truck choice and freight forecast assumptions, then adjusted incentives and truck retirement age, first targeting the ratio and counts of internal combustion to ZEV stock in META for 2031.

The complete -- to complete the assessment of Energy Commission and load impact, colleague Alex Lonsdale dove further into the VMP and energy-consumption totals. Resulting incentives were set for each truck class, varying from 25 percent of the purchase price for class 3 to 65 percent for the class 8 tractors, with a retirement age for the tractors after 13 years of operation.

Alex calculated the fraction of VMT and fuel consumption from our model's Los Angeles zone, corresponding to the South Coast -- including the South Coast Air Basin, then applied load changes that determine the additional peak demand for the Edison territory. We found that using vehicle stock totals is a pretty rough circuit for emissions, so a future use of this scenario will assign incentives and retirement based on the fuel consumption outputs, results. Note that the -- in the Appendix of this slide will show an alternative scenario with retirement after 15 years of operation and an incentive of 80 percent for the class 8 tractors. But we'll cover that otherwise. The next slide, please.

Comparing our forecasting data to that in the META tool, we found that our vehicle stock is lower in the base year, mostly because META includes class 2B, trucks advanced between 8500 and 10,000 pounds gross weight, while we start with from the 10,000 pounds up. Economic growth in META is based on Metropolitan Planning Organization forecasts, while ours is based on commodity movement and freight analysis framework and providing services scaled to fit the trajectory of Moody's Transportation and Distribution Forecasts, which accounts for Covid.

In META, ZEVs are introduced to meet the 2031 Ozone Standard, while in our model ZEVs are introduced according to an adoption curve in the truck choice model scaled based on total cost of ownership, in competition with other fuels. META uses the miles per vehicle from EMFAC 2017, while we use the 2017 California Vehicle Inventory and Use Survey. For our model, less new trucks are needed to meet demand since newer trucks go more miles in a year than the older ones they replace and the number purchased is set to meet demand for goods and service trucks. This is one reason using ICE and ZEV stock ratios to set incentives and retirement is not as accurate as it would be if we used fuel consumption. Next slide.

So now we just move on to our results. Next slide.

Here we see a comparison of internal combustion stock on the left with ZEV stock on the right. The CEC mid case is light blue, META is gray, and the attainment scenario counts are in dark blue. Number of ICE vehicles in attainment, dark blue, are lower than META's except for class 3, while class 4 and 5 attainment has less than half the internal combustion and double the ZEVs. This happened because we over shot on the incentives. Overall, the attainment -- I'm sorry. Next slide, please.

Overall the attainment scenario ends up with the largest number of ZEVs, mostly because we over shot class 4 and 5. Using fuel consumption as the target to set incentives and retirement will allow us to fine tune the classes going forward. Next slide, please.

Here we see the battery electric truck VMT in 2031 for the CEC mid case in light blue and the increase under the attainment scenario in dark blue. The class 8 VMT is almost all these class 8 tractors, about 2.6 billion zero-emission miles for attainment between the three classes shown here. Next slide, please.

Here is diesel consumption, where we could clearly see the dominance of class 8 tractors. Diesel totals under the attainment scenario in total are lower than META, but this is distributed unevenly: Higher in class 8 and lower in class 4 and 5, and class 6 we didn't show. The class 7 difference is mostly due to the differences in total forecasts stock between us and META. Next slide, please.

Gasoline totals on the left and compressed and liquified gas on the right. Most gasoline is medium duty and most gas is heavy duty. Attainment totals are lower than META because of competition from low diesel process and low NOx gas is no longer being incentivized -- low NOx gas vehicles are no longer being incentivized in HVIP. Slide 14, please.

Annual electricity consumption in 2031 is about 1700 gigawatt hours more than the mid case. Approximately 70 percent is in Southern California Edison territory, 27 percent in LA Water and Power and two percent in Burbank Water and Power. This adds 164 megawatts beyond the mid case to SCE's summer peak. That's weekday hour 19, 5:00 p.m. in

2031. Next slide, please.

Takeaways. ZEV populations from different models should not be compared without also considering Vermont and fuel consumption. The intent of the State's ZEV goals is to reduce criteria pollutant emissions and GHG emissions, which are dependent on VMT, the portion of VMT driven by zero emission versus internal combustion.

Staff recommends that ZEV goals and metrics be in terms of reducing emissions and fossil fuel use, in addition to a vehicle population target, or even in place. Slide 16, please.

Here is my contact information. I want to acknowledge the amount of collaboration Alex and Heidi Javanbakht provided, as well as Ian MacMillan and Sara Forestieri as helping the analysis -- or helping frame the analysis, providing data and answering questions.

Please ask questions or write, add written comments, since this was exploratory work and will continue to evolve. Thank you.

MS. RAITT: Thank you, Bob.

Commissioners, do you have any questions for Bob?

LEAD COMMISSIONER MCALLISTER: I am not going to ask any right now, Bob. Very interesting. But I want to leave time for some public comment for that, so I will pass it on to my colleagues on the dias.

VICE CHAIR SCOTT: I don't have any questions either. I do want to acknowledge again the increasing sophistication of our work to really be able to dig into and look at zero-emission vehicles and the options and what do they mean for our system. So I appreciate that work.

And I appreciate kind of the good work together with the South Coast Air Quality Management District to think through and compare studies and then understand if there's places where we have slightly different answers, where those are coming from. I think that kind of data and information is really useful and helpful, so thank you all for getting that done.

MR. MCBRIDE: Thank you, Commissioner.

COMMISSIONER MONAHAN: Yeah. Bob, I actually only have a comment, not a question. And my comment is that, you know, when we look at that aggressive case for electrification, it was a hundred thousand, right, in 2030, Bob, to reach the NOx, to reach the attainment to South Coast?

MR. MCBRIDE: Sounds right. I'd have to look.

COMMISSIONER MONAHAN: Anyway, so around that, and just to give us some perspective, like from -- so there is a city in China called Shenzhen, kind of -- it's a very green city, but so is Los Angeles, let's face it, and it has about the same population, so around thirteen-ish million in that metropolitan area in Shenzhen. And Shenzhen in the last three years has gotten 60,000 light trucks on the -- you know, small trucks, delivery vehicles. They're trucks and they're delivery vehicles. And 16,000 of their buses are electric. So it's close to 80,000 of heavy-duty vehicles in three years. The same population.

So I think when we look at the aggressive case and they go, oh, my God, we can't reach that, I would just say one city, in Shenzhen, almost has done that in three years. And, you know, so I have more optimism that we should be able to also break some of these barriers around electrification. That's my comment.

But thank you, really interesting research and really important because I mean at the end of the day it's all about clean air for California. That's the biggest driver I think for all of us, is we want to have a safe environment for the future.

MR. MCBRIDE: Yes. Thank you, Commissioner. Doing this was recording -- was valuable to us, new territory.

MS. RAITT: All right. So Heather again. Thank you again, Bob, for that presentation.

So I think we are ready to move on to the public comment period. So we will be opening up lines for public comment and ask that -- we just have one person for organization comment and the comments will be limited to three minutes per speaker.

So if you are using the online Zoom platform, you can raise your hand to let us know you'd like to comment. And if you're on the phone, just dial star 9 to raise your hand, and then again star 6 -- excuse me -- to mute and unmute your line.

And RoseMary Avalos from the Public Advisor's Office is here today to help us with public comments.

MS. AVALOS: Thank you, Heather.

I will first call on attendees using the raised hand feature on Zoom. Please state your name and affiliation and spell your first and last name. Also please do not use the speaker phone feature because we may not be able to hear you clearly.

As I can see right now, I don't see any raised hands, so I'll also remind those that are on the phone to dial star 9 to raise your hand and star 6 to mute and unmute your phone line. So, okay, we have Doug Karpa.

Go ahead and you may need to unmute on your end. Go ahead and speak. Doug.

MR. KARPA: Yeah, hi. I don't know if you can hear me. This is Doug Karpa from Peninsula Clean Energy. I really want to thank everybody at the Energy Commission for all this great work that you all do. It's always a good day to hear from you all.

I was actually curious a little bit about the prospect for doing analysis on some of the results that we're going to see out of the SB100 study I guess at the Workshop tomorrow. In particular, we're hearing a lot -- or I'm hearing some discussion about how much increase spending on generation, renewable generation is driving electric sector carbon emissions down might hamper like building and EV electrification. And I realize listening to this that we already have a lot of the data -- or you already have a lot of the data about the sensitivity of PV adoption and I presume public building electrification as well to electricity rates.

And so it'd be really interesting, I think, to get an empirical look at, say, you know if we take a 2045 scenario that reduces the emissions from, say, 24 million metric tons down to, say, I don't know, 8 or 10 or 5, what some of the other results are, what actually would be the impact on actual customer bills and then how do those customers' bills translate into costs per mightily and how does the cost per mile then translate to rate of transportation electrification.

I guess it's more of a comment than an actual question, but I'm just realizing that you all are beautifully set up to do that analysis, given infinite time.

So thank you again so much for all your work.

MS. AVALOS: Thank you, Mr. Karpa.

And I will go ahead and remind those who want to speak to please raise your hand on Zoom. And, again, those on the phone dial star 9 to raise your hand.

Are there any other comments? Please raise your hand now.

I'm going to give it just a couple more seconds and see if there are any other raised hands.

I don't see any raised hands, so I will go ahead and turn it over to Heather.

MS. RAITT: Thanks. So that concludes the public comment portion.

And so, Commissioners, if you wanted to make any closing remarks you're welcome to.

LEAD COMMISSIONER MCALLISTER: Well, thanks to all the staff who presented. I'm really pleased about a really deep analysis. And it's both heartening to see the progress that's been made on some of the analytics just even since the last full IEPR. Again, there's just been steady progress every cycle and half cycle for the last -- well, ever since I've been at the Commission and certainly ever since I've been looking after the forecast.

And you know driving our decisions with better and, you know, generally more granular but certainly more vetted data sources is just where we're going generally. And

I see everyone -- I think everyone saw that today in the presentations and, really, that staff are taking it to heart and really working across many, many stakeholder groups to get better information and to develop algorithms that make sense and to vet those algorithms with experts in each particular sub field, and so that's terrific.

I really did, Bob, appreciate the talking -- the work on NOx and focusing on the nonattainment and trying to figure out ways we can, you know, as a state reduce those. Obviously transportation is a big one, and working across the agencies. It's good to see some other agencies online paying attention to this, so looking forward to working together with all of you.

So, with that, I think I'll pass it back to my colleagues if they have some final wrap-up comments before we break for lunch.

So, Vice Chair Scott.

VICE CHAIR SCOTT: Thank you. I did not actually. I just want to say thank you to the staff for the excellent analysis and presentations.

LEAD COMMISSIONER MCALLISTER: And, Commissioner Monahan, did you want to wrap this up before lunch?

COMMISSIONER MONAHAN: Well, I was really impressed actually with the breadth and depth of the modeling that staff is undertaking, and just the creativity and the willingness to try new things and to really explore, you know, new techniques for modeling how to reach the clean transportation future that we need for the health of our children, the health of our planet, so just I want to give thanks to the staff for doing that. And I think we still have a lot of work to do, like a good analysis always leads to more analysis. And I think this is a scenario where we really have -- I wouldn't say a dearth of information, but we definitely have some information gaps that we need to work on, and I'm heartened by what the team is doing.

LEAD COMMISSIONER MCALLISTER: Very well.

Well, thanks very much.

In the afternoon we're going -- we shift gears a little bit to talk about the overall electricity demand forecasts update and some focus on self-generation and distributed energy, so looking forward to that. And so we'll be back at 2:00.

Heather, did you need to say anything before we adjourn for mid-day?

MS. RAITT: No, that's it.

Just a reminder to folks that we also have a new webinar I.D. number, so log back in at 2:00 and we'll look forward to seeing you then.

LEAD COMMISSIONER MCALLISTER: Great. Thank you. Thanks, Heather and team, for organizing and keeping us on track, really appreciate it. So we'll see everybody at 2:00.

(The Workshop was recessed at 12:23 p.m. or lunch and resumed with Session 2 at 2:00 p.m.:)

SELF-GENERATION and OVERALL ELECTRICITY DEMAND FORECAST UPDATE

MS. RAITT: Good afternoon, everybody. Welcome to the 2020 IEPR Update Commissioner Workshop on Updates to the California Energy Demand 2019 through 2030 Forecast. I'm Heather Raitt, the Program Manager for the Integrated Energy Policy Report, or IEPR, for short.

Today's Workshop is being held remotely, consistent with Executive Orders N-25-20 and N-29-20, and the recommendations from the California Department of Public Health to encourage social distancing to slow the spread of Covid-19.

To follow along with today's presentation, they have been docketed and posted on our website, so you can find them there. And all our IEPR Workshops are recorded in both a recording, an audio recording and a written transcript will be posted on the CEC website within a few weeks.

We are -- if you were here this morning, we are again going to use the Q and A function on Zoom, with the ability to upload questions. So if you have a question for the speakers, go ahead and click that Q and A icon, and you can type in a question, and we'll reserve a few minutes at the end of the speaker sessions to address any questions that come in.

Now I will go over how to provide comments on the Workshop today. So there is going to be an opportunity for public comments at the end of the presentations. Please note that we will not have time for presenters to answer questions during that time. You can click the raised hand icon to let us know that you'd like to make a comment, if you're using the electronic device to join us. And if you're joining us by phone, press star 9 to raise your hand, and we'll open up your line during the public comment period.

Alternately, written comments are always welcome. And for this Workshop, they are due at 5:00 p.m. on December 17th. And the meeting notice provides all the information you need for any comments.

And, with that, I will turn it over to Commissioner McAllister. Thank you.

LEAD COMMISSIONER MCALLISTER: Very well. Thank you, Heather. Appreciate that.

Well, thanks to everyone. I see the numbers ticking up as people log in, so thanks for coming in for round two of our -- of our bill today. Really looking forward to -- this morning was great, actually. Lots of substance and really I think for those of you who were there, we realized how far we have come really on the transportation side of things in terms of the sophistication of our analysis, commensurate with the incredible developments in that part of our economy, so really heartened by that and excited for what's to come. I'm impressed by the analysis this year and excited of what's to come next year and beyond. So thanks to the staff this morning.

So this afternoon we're turning to a different set of topics, the forecast, the Electricity Forecast, and some of the proponents of that and so we're really excited about this. Lots of meat here too. Certainly with the Covid challenge and the manifestations of climate change that hit us this summer and the excitement around the forward planning we're doing and the assessment work we're doing for the longer term around SB100, there are certainly a lot of parallel themes that the forecast has to sort of embrace and contend with and explore around. And so it's part of what the forecast team has been doing for this year specifically but also kind of trying to chart a path for next year and beyond with the overall forecast as well.

So obviously the Covid challenge has really impacted the way energy is used in all parts of the energy sector and understanding that and trying to update our forecast to account for that is tricky and requires a lot of situational awareness and creativity. And so I'm really indebted to staff for taking this on.

And, in particular, I wanted to thank the forecasting team and just call out Nick -- we'll hear from all of these folks today -- but Nick and Jerry, Sudhakar, Matt, Heidi, and the Transportation team, really the whole forecasting team for the morning and the afternoon. There is a real deep niche here, a lot of great skills and a complementary set of staff understandings and expertise that really helps this machine function and move on in a well-lubricated fashion. So really want to think all the leadership from Siva and Aleecia on down in the Assessments Division.

So, with that, I'm just excited to see what's on offer today and to have a look and hear what folks have to say, so I'll pass it to any of my colleagues who happen to be here. I haven't checked to see who from the Commission is here, but if Vice Chair Scott or Commissioner Monahan, Commissioner Douglas, or Chair Hochschild are on, I'm happy to hear from them as well.

VICE CHAIR SCOTT: Hi. This is Vice Chair Scott.

LEAD COMMISSIONER MCALLISTER: Hey.

VICE CHAIR SCOTT: I am here. Thanks for the invitation. I don't actually have any opening remarks to make, but I am glad to be hear and look forward to hearing the data and the presentations.

LEAD COMMISSIONER MCALLISTER: And a me too to that, just here to listen and learn. Appreciate everybody doing such a great job on the forecast and look forward to hearing what your results are.

MS. RAITT: Great. Well, then this is Heather. I will go ahead and introduce our first speaker. I'd like to introduce Sudhakar Konala. Sudhakar is the Energy Assessments Division Subject Matter Expert on Self-Generation and Sudhakar models the adoption and operation of behind-the-meter resources, most notably photovoltaics and battery-storage systems.

So, Sudhakar, go ahead and -- go ahead and take it. Thanks.

MR. KONALA: Hi, everyone. So good afternoon, Commissioners, valued stakeholders, members of the public. My name is Sudhakar Konala. Today I will present the Behind-The-Meter PV and Energy Storage Forecast results that were developed in the 2020 California Energy Demand Forecast Update.

So to start off, I would like to just briefly provide an overview of today's presentation.

Today's presentation will cover four main topics. First, I will briefly review the historical behind-the-meter PV installation data that was updated for this forecast.

Second, I will go over the other inputs that were updated in the forecast. Then I will present the results of the PV forecast. And, finally, I will present the results of the behind-the-meter Storage Forecast, while highlighting any methodological changes made in the Storage Forecast.

But before I get the actual forecast I would like to also briefly recap some of the changes that were introduced in this year's PV Forecast. For this forecast, staff began to use interconnection data that utilities started providing to the Energy Commission. This resulted in revisions to the historical PV installation data.

While the effect on aggregate installed capacity for the IOUs was small, for some of the POUs there was significant revisions in the known amount of installed PV capacity. And this gets into our historical data, so revisions to historical data.

Second, to impart some new data, staff also includes the classification of PV systems to better align with the Energy Commission's sector and subsector classification system.

Third, staff also updated the capacity factors used in calculating the generation from PV. Although the data source for capacity factors remains the same, staff used system tilt orientation data to create an orientation-weighted capacity factor for each region.

In the previous forecasts, the capacity factor for a single tilt and orientation was used to calculate energy for PV systems. All of these changes were described in detail in the August 28th IEPR Workshop. And I have provided a link to that presentation for anyone that's interested in more information. Next slide, please.

So this chart shows the updated and historical PV data. The gray bars indicate the amount of installed capacity at the beginning of a year, while the green bars show a newly added capacity that came online in a given year. In summary, the chart shows that statewide PV capacity at the end of 2019 was over 9,400 megawatts, up from less than 1,000 megawatts at the start of the decade. Next slide, please.

This slide shows the same data but in a slightly different fashion. It shows in more detail the annual additions to PV capacity since 2005, broken down by sector. The chart shows that there has been significant growth in PV from 2005 through 2016. However, it also shows that since 2016, annual installations have held steady at about between 1300 and 1400 megawatts. This is an indication that the PV marketplace in California may be maturing. Next slide, please.

Moving on, I also want to look at what's happening with PV installations in 2020. There are several new factors to consider regarding solar options in 2020. First of all, this is the first year where the federal investment tax credit has decreased, going from 30 percent in 2019 to 26 percent this year.

Second, this is also the first year where Title 24 PV requirements are in effect for new residential construction in California. So we would expect this to lead to a higher adoption in the residential market. But of course there is also a pandemic going on and the economic downturn, so there is a lot going on this year.

Now I've pulled the data for the first half of 2020. And in this chart I have compared it to installation data from the first half of 2019 as well as 2017 and 2018. And the main point from this chart is that compared to 2019, there really isn't that much change in adoption in PV in 2020. So I've broken this down by IOU and by sector; they're residential or nonresidential. And for each -- for each cluster you can see that it's relatively the same since 2019.

So overall what this shows is that while installations remain the same, there also just isn't enough data so far to discern how all of the different factors I described above are affecting the adoption so far this year. So we don't really see an effect from the Pandemic, but we don't know if it's because there is an effect and it's being overshadowed by increased adoptions into Title 24 PV requirements, we just don't know yet. Next slide, please.

So moving on to the forecast, I want to briefly want to cover some of the updates made to the inputs, and then share the statewide results. Next slide, please.

So I just wanted to add this slide to be complete in my presentation, but I won't have time today to describe the workings of the models in depth. So this is just a chart that just summarizes how the models work, a very high level chart.

The main thing I wanted to point out are all the different inputs that go into the Energy Commission's PV models. So that includes updated historical statewide installed capacity, which I had just gone through. They also include updates to economic and demographic data, which I will discuss. It also includes updates to the Fuel Price Forecast and usually also updates to the system cost and performance and other system data.

So in terms of system performance, the revised capacity factors are an example of that. And then we just take these data, we feed it into the models, and the models provide an estimate or a forecast of installed behind-the-meter capacity, which we then use to do a forecast of energy generation from behind-the-grid PV. Next slide, please.

So in terms of the updates, we want to go over some of the updates that we made for the inputs for this forecast. Of course for every forecast, staff update several important inputs. These include: Economic and demographic data, such as the forecast of household growth; commercial floor space; electricity rates; and also installed cost of solar; and also inflation.

Looking at the inputs to this year's forecast, at the statewide level we had slower growth in new single-family homes. We also had slightly lower growth in commercial, in the commercial floorspace forecast.

The forecast change in electricity rates, compared to last year's forecast, were actually pretty similar. So there wasn't that much change from last year.

Finally, staff also included new commercial sector TOU tariffs for PG&E and also updated commercial sector tariffs for SMUD. So for PG&E, starting in 2021, I believe, PG&E is going to introduce new tariffs that go with the B nomenclature, B-1, B-6, B-10, B-19, B-20. And then SMUD is also restructuring some of its commercial TOU tariffs in 2021. That is an ongoing process that goes on for several years, but for the -- for 2021, the changes that are in effect in 2021 we can incorporate to the forecast. The changes that go beyond 2021 will be incorporated into next year's forecast. Next slide, please.

So before I get into the forecast results I also want to discuss how scenarios are defined in the California Energy Demand Forecast and specifically how that pertains to the PV forecast, because it can be a bit confusing. The three scenarios are described to create a high, mid, and low level of electricity demand. By definition, in the high-electricity demand case, we want to model a higher level of electricity demand, which means we have to model a low level of PV adoption.

Conversely, in the low-electricity demand case, we want to model a low level of electricity demand, which requires to have to model a high level of PV adoption. Everyone should keep in mind in the upcoming slides that this is the nomenclature that we use, because otherwise the labeling gets counter intuitive and it can easily get confusing. Next slide, please.

Now turning to the actual forecast, this slide shows the historical as well as forecast of electricity generation for behind-the-meter PV in the state of California. In 2019, behind-the-meter PV generated an estimated 15,800 gigawatt hours of electricity. By 2030, generation is projected to grow to nearly 35,000 gigawatt hours in the high-demand case, over 41,000 gigawatt hours in the mid-demand case, and over 47,000 gigawatt hours in the low-demand case.

Compared to the mid case of the 2019 forecast, generation in the near term is slightly lower due to the lower PV capacity factors that I described earlier as well as lower adoption of PV in the residential and industrial and agricultural sectors in the early part of the forecast. However, generation by 2030 is expected to be roughly the same as the previous forecast due to higher adoption of PV in all sectors in the second half of the decade. Next slide, please.

This slide shows the total energy from all self-generation within the state broken down by PV and nonPV technologies. In 2019, an estimated 30,000 gigawatt hours of electricity was produced in the state. Roughly 14,000 gigawatt hours of that total came from technologies other than PV, most of which was large-scale industrial cogeneration. Over the forecast period, this nonPV generation is expected to remain relatively steady, while PV grows at a significant pace, as I described earlier.

So this concludes the Overall Statewide Forecast for PV Generation. Now I'm going to move on to the individual forecasts for each utility and planning area. Next slide, please. Next slide.

This slide shows the forecast of electricity generation for behind-the-meter PV for PG&E and the POUs within the PG&E planning area. In 2019, behind-the-meter PV generated roughly 7,300 gigawatt hours of electricity. By

2030, PV generation is forecast to grow nearly 1900 gigawatt hours -- I'm sorry -- 19,000 gigawatt hours in the mid-demand case and to over 21,000 gigawatt hours in the low-demand case and 16,000 gigawatt hours in the high case.

Forecast PV generation is slightly lower in the near term compared to the previous forecast, but similar to the previous forecast after 2025. The chart also shows a slight reduction in estimated generation over the historical period compared to previous forecasts. This is evidenced by the dark gray line which represents the revised historical generation that I described earlier. Being lower than the dotted lines in both the 2017 and 2018 forecasts, which represents estimated historical generation in the previous forecast. Next slide, please.

Moving on to Edison, this slide shows the forecast of electricity generation from PV for Southern California Edison and the POUs within the SCE planning area. In 2019, behind-the-meter PV generated roughly 5,100 gigawatt hours of electricity. By 2030, PV generation is forecast to grow to about 14,000 gigawatt hours in the mid-demand case, over 16,500 gigawatt hours in the low-demand case, and 11,700 gigawatt hours in the high-demand case. Forecasted PV generation is slightly lower than the near term again compared to the previous forecast and slightly higher over the long term, primarily due to the higher forecast of PV capacity in the commercial and industrial sectors after 2025. Next slide, please.

Now this slide shows the forecast of electricity generation from behind-the-meter PV for San Diego Gas & Electric. In 2019, behind-the-meter PV generated an estimated 2,080 gigawatt hours of electricity. By 2030, PV generation is forecast to grow to roughly 4,500 gigawatt hours in the mid-demand case, or 5,000 gigawatt hours in the low-demand case, and about 4,000 gigawatt hours in the high-demand case.

The forecast in the mid case is slightly higher than the forecast from last year. San Diego Gas & Electric consumers continue to adopt PV at a very high rate compared to other regions of California. We have seen this in the historical -- throughout the historical record and it was true again in 2019. However, PV adoption in SDG&E's territory is forecast to slow down in the second half of the decade, as the residential rooftop markets -- as the residential rooftop solar market reaches saturation more quickly than other areas. Next slide, please.

Now turning to the PV forecast for LADWP, in 2019 estimated PV generation was about 516 gigawatt hours. This is noticeably lower than previous forecasts, as indicated by the dotted lines, due to a significant revision to historical PV installation data.

The interconnection data provided by LADWP showed lower PV adoption than the data the Energy Commission had previously collected through incentive programs. By 2030, PV generation is forecast to grow to about 1200 gigawatt hours in the mid-demand case, over 1300 gigawatt hours in the low-demand case, and 1,000 gigawatt hours in the high-demand case.

The revision to historical data also helps to explain the lower forecast for PV generation for LADWP compared to previous forecasts. A lower forecast of household growth also has a larger effect on LADWP's forecast, especially since LADWP derives a greater share of solar adoption from the residential sector than other utilities. Finally, staff continues to use data from incentive programs rather than interconnection data for LADWP for some historical years. Not all but for some historical years. This was due to some missing information in the interconnection data provided to the Energy Commission. Over time, as LADWP's interconnection data becomes more complete, further revisions to historical data are possible. Next slide, please.

Finally, we turn to SMUD. Like LADWP, the chart shows a downward revision in the estimated historical PV generation for SMUD, indicated by the dotted lines being higher than the gray lines for 2017 and 2018. This is largely due to lower adoption of PV being reported in interconnection data compared to the incentive program data that the staff had previously used.

In the new forecast, estimated behind-the-meter PV generation in 2019 was 312 gigawatt hours. Generation is expected to reach roughly 1200 gigawatt hours in 2020 in the mid case. The forecast of PV generation in the mid case continues to stay lower through 2030 compared to last year's forecast in the mid case. A large part of this is due to the revision of the historical data, and we're just catching up over time but not quite reaching the level that we had forecasted last time.

Furthermore, these results do not consider the effects of SMUD's Community Solar Program, which was approved by the Energy Commission in February. We've had discussions with SMUD, and they have shared some of their assumptions about participation in the Community Solar Program, but they have also said that they just won't have -- or they won't be able to share any data about that participation until some time in 2022. And so since we don't have actual data, it is difficult to predict the rate at which homebuilders may opt into the program.

Since data for participation in the Community Solar Program is not anticipated before 2022, we felt it was prudent to not include any effects of the Community Solar

Program until the time that we do have some data that we can base assumptions upon. So it is important to consider the Community Solar Program once we have data, but we're going to wait until we actually have some data.

It's also important to consider that once participation in the program is taken into account, solar adoption in SMUD's territory could be lower in the program than what we are forecasting, so please keep that in mind as well.

So that wraps up the solar portion of the forecast. Now I'm going to move on to the Energy Storage Forecast. Next slide, please.

In terms of forecasting behind-the-meter energy storage adoption, staff did not make any changes to the methodology from the final 2019 Forecast. We incorporated the latest data from the Rule 21 datasets as well as the SGIP storage installation datasets. The Rule 21 dataset was used for forecasting the residential adoption, while the SGIP data was used to forecast nonresidential storage adoption.

Looking at the data, actual storage adoption in 2019 was much higher than we had forecast. For example, last year's forecast projected between 70 and 85 megawatt hours of behind-the-meter storage to be installed in 2019, when the actual amount was closer to about 130 megawatts.

Similarly, looking at SGIP program data, the data shows a significant increase in the number of current applications for funding for storage projects. As of November 2nd of this year, there were about 470 megawatts of outstanding reservations for funding. Compare that to about 70 megawatts of reservations for funding at the same time last year. Next slide, please.

So with both higher installations in 2019 and more applications for future funding, the signs point to more storage adoption than what the -- than what the 2019 Forecast projects. So in the 2020 Forecast, we see a significant revision upward in the forecast. In the mid electricity demand case, the forecast nearly doubles the amount of storage in the state by 2030, compared to last year's forecast. And, as this chart shows, by 2030 we're forecasting storage in the mid case to be about 2,600 megawatt hours, compared to about 340 megawatt hours -- of megawatts that we have today. Next slide, please.

Staff often also gets requests about sharing data about storage capacity, especially since we don't publish this online. So I've taken this Workshop as an opportunity to do that, so I wanted to include a table that just shows the forecast of energy storage capacity for PG&E, Southern California Edison, and San Diego Gas & Electric by demand case. I want to emphasize that although the forecast is significantly higher this year than last year, the methodology for forecasting storage adoption remains the same as last year.

Finally, the table also shows that the forecast of storage adoption by POU customers is low compared to the IOUs. This reflects two facts. First, observed historical data for POUs does show lower adoption than IOUs. But also the storage data for POUs is also incomplete, so in the future if we get more complete data this observation could change. Next slide, please.

In terms of how storage systems are used, staff has updated some of the charge and discharge profiles that were used in the 2019 forecast. For nonresidential storage systems, new charge/discharge profiles published in the 2018 SGIP Storage Impact Evaluation Report, which was released earlier this year, were used. For residential storage, storage systems seeking SGIP funding are subject to new SGIP requirements. Specifically, SGIP now states that all new residential IOU and nonIOU customers are required to enroll in a time-varying rate with a peak period starting at 4 pm or later with a summer peak to off-peak price differential of 1.69 or more, if such a rate is available. Next slide, please.

This means that part of how staff modeled the deployment of residential storage is now out of date, as new residential storage customers seeking SGIP funding no longer qualify for some of the TOU tariffs that were used in the 2019 forecast. The table in this slide shows the tariffs that were used to model residential storage in 2019 as well as the tariffs that are available to new -- sorry -- to new residential applicants who want SGIP funding.

For SMUD customers, there is only one TOU tariff, so there is no change. For San Diego Gas & Electric customers that want to adopt storage, they have to switch to one of four tariffs. However, staff believes that most customers will choose Option 1 in this table, which is very similar to the tariff that was modeled last year. Thus we believe we can keep the charge/discharge profiles for San Diego Gas & Electric the same as last year.

But for PG&E and Southern California Edison, the story is different. For PG&E and Southern California Edison, the available options are quite different from those that were modeled last year, and this requires staff to model new charge and discharge profiles this year for these two utilities. Next slide, please.

So this slide shows how we anticipate charging and discharging to change due to the new SGIP requirements. On the left side, you can see when residential storage systems were allowed to discharge for PG&E, on the top, and Southern California Edison, on the bottom, in the 2019 Forecast. On the right side, you can see when we expect residential storage systems to be discharged under the new tariffs. The discharging is displayed by the green -- the boxes that are shaded green, so I just want to point that out.

So the figures also specify the tariffs that we anticipate most customers to choose under the new rules, so you can see there on the right side by the dots in the red color. Overall we expect the total hours where it makes sense to charge to increase for PG&E customers, but to decrease for Southern California customers. And this is just modeling discharging based on the optimal pricing that is specified in each of these relevant tariffs, compared to the tariffs that were available to storage customers in 2019.

So this wraps up the Storage Forecast and my prepared presentation. So if anyone has questions, I can take those.

LEAD COMMISSIONER MCALLISTER: Commissioner Scott, did you want to have -- did you have a question in or not?

VICE CHAIR SCOTT: I do not. Actually I don't have any questions.

LEAD COMMISSIONER MCALLISTER: Okay, good. Okay, great. Yeah, terrific.

So thanks, Sudhakar, I was wanting to get an update about the refresh, the historical piece, so that was good. I don't have any specific questions. I feel like I've been pretty up to date to this, but I really appreciate your -- all the work on both the self-gen piece and the battery piece, so thanks a lot on that.

MR. KONALA: Thank you.

MS. RAITT: All right. Well, I guess actually if we could turn to -- if there are no more questions from Commissioners -- Matt Coldwell, the Manager -- oh, Commissioner, do you have another -- okay. We have Matt Coldwell, the Manager from the Demand Analysis Office, is here to help us with moderating questions from Zoom.

And I think there were a couple of questions on Zoom, if you wanted to get those.

MR. COLDWELL: Yeah. Thanks, Heather.

Sudhakar, there's a few questions here for you. So just -- I'm actually going to read the shorter ones first here: Is electricity demand part of the input for PV Generation Forecast?

MR. KONALA: No. The PV Generation Forecast does not factor in electricity demand. So it does -- okay. For individual systems, we do model obviously demand to the size of the PV system, I guess if that helps. But beyond that, it's not part of the Generation Forecast.

MR. COLDWELL: Great. Okay, so the next question is -- I think I know the answer to this, but before I answer it I want to make sure I was right and get you to answer it

-- is: Does the CEC forecast behind-the-meter PV capacity as well as energy?

MR. KONALA: Yeah, we do. And I -- I do have a forecast of that, I just did not share it this year because I did not have the time. But, yeah, we have all of that information, so just -- people can shoot me an email if they would like the forecast for behind-the-meter capacity. I have all of the data.

MR. KONALA: Great. Thanks. And one more, one more question, and I'm sorry, I should have mentioned who the questions were from, the last one was from Tim Drew. And this question is also from Tim Drew. This one is a little longer. Can the CEC's behind-the-meter PV forecast models be modified to generate different scenarios based on assumptions or revisions to the tariff. So -- and he gives these -- sort of the bookend examples of NEM, NEM not changing versus sort of the elimination of compensation for exports.

MR. KONALA: Yeah. So they can -- they can be modified to generate forecasts based on scenarios for different assumptions for NEM. And actually the forecast already does do that, so -- and this is had been the case for at least the last four years. So in the low-demand case, where we're projecting very high levels of PV adoption, we assume that we have full retail compensation for exports, exported generation from PV.

In the high-demand case, which -- which assumes low PV adoption, we modeled a hypothetical successor to NEM 2.0 which assumes that excess generation on a monthly basis is compensated at about 10 cents per kilowatt hour and there is also a grid charge as well, but I can't quite recall what that charge is. But this has been constant for the past four years.

There have been some discussions about NEM 3.0 coming out next year, and I'm following, you know, very closely to see what that might be like. And if that does come to pass, we'll try to include those results in the next year's forecast by updating some of these NEM assumptions.

MR. COLDWELL: Great. Thanks, Sudhakar.

That's all the questions that we have in the Q and A box. So, Heather, I don't know if I'm turning it back to you or the next.

MS. RAITT: Sure.

MR. COLDWELL: Okay.

MS. RAITT: Thank you, Matt.

And thank you, Sudhakar. Really appreciate your presentation.

We can go ahead and move on to the next set of presentations of -- and I will go ahead and introduce Cary Garcia. He'll start the discussion on Electricity

Consumption and the Peak Demand Forecast Updates. So Cary is the Lead Analyst responsible for coordinating many of the elements of the Demand Forecast at the Energy Commission.

So go ahead, Cary.

MR. GARCIA: Thank you.

Yeah. So today, as Heather, mentioned I'm the Lead Analysis here at the Demand Analysis Office, so I will be presenting on the Consumption and Sales Forecast Results. I'm going to just dive into a general overview of the process, the inputs for the analysis, a statewide summary, and get into some of the planning area summaries.

And I also -- I know we did some thank-yous usually at the end of our presentations, but I want to do this one at the beginning, actually. And there's two people that we generally -- are kind of behind scenes and we don't see a whole lot of their presentations. And those two people are Julianne Alontave and Nancy Tran.

So Nancy Tran, I'll start with her, particularly in this situation with the data that we're getting for the economic inputs, she's been super helpful. I think I've been bugging her almost around the clock for various bits and pieces of data, what the latest is happening as far as the economy.

And then Julianne Alontave works on our QFR data, which is our energy reporting. So she -- that's sort of our backbone of our forecasts. It's crucial that we have good, accurate data to generate these forecasts. And similar to Nancy, I bug Julianne it seems like around the clock. Hopefully she doesn't hate me too much for that, but she has been super helpful and awesome and were too big parts of our forecasting team, although now they're sort of in a separate office, our Data Integration Office, but, again, super helpful. So I just wanted to get those thank-yous out there.

But we can move on to the next slide. Getting into the update process. So our Forecast Update process was basically developed to account for economic changes between our full -- air quotes -- full forecast cycle, where we use our end-use models. And so in this update we are generally using econ metric models that we run alongside our end-use models, and then typically provided similar results.

So to get a more streamlined process in between these more and intensive IEPR cycles, the full IEPR cycles, we run these models and, essentially, prepare results using the older, vintage of data that we used in CED 2019, and then the new set of data that we have now. And the difference between those models essentially gives us an adjustment factor that we can apply to our previous end-use model results. So that's what the basis of our update is.

Demand modifiers, such as EV and self-generation, we talked about those earlier today. Obviously, those are being reestimated. And then we leave committed savings in AAEE as well as climate change, the same as it was in 2019 except to rescale to adjust to our new starting point. So in this case we added an additional year of historical data, 2019. Whereas our CED 2019 forecast would have started from 2018, the actual history.

And then a note. We kind of talked about it a little bit today, about Covid-19. This is at the top of our minds, given everything that's happening this year. Just a note on that, you know, the update process, as I mentioned, really is focused on these economic changes. It's not really suited for a study of structural impacts and what those may be in the long term, so that's one of the shortcomings of this particular analysis. You know our commercial and residential end-use models will definitely be more suited to capture and potentially make some adjustments based on information that we can gather about what's some potential structural changes may be and how model going forward. For right now, really the model, the economic process that we're using right now is really focused on the typical changes to the economy that we have seen in the past. So I'll talk about that a little bit more, but the basics are changes to employment, we know are pretty dramatic, and changes to our normal inputs such as housing projections and population. Next slide.

This is just an overview. Sudhakar touched on this as well and we all kind of touch on these in our presentations. This is essentially our demand scenario assumptions broken out here for the different scenarios that we have. Largely, the same. I mean they're basically the same as we used last year. The goal here really is to capture the certainty of potential outcomes. Our mid case, for example, is tied to a base economic case for Moody's Analytics, what they would characterize as a 50-50 outcome, a 50-percent probability being above and a 50-percent probability being below that base case.

The high case here is tied to a higher economic output, demographic growth. The economic case is derived from Moody's custom scenario that they developed for us. And, generally, it's just more optimistic in the potential long-term outcome. You will see there is higher EV adoption in that demand -- high-energy demand case to higher climate change impacts, but what Sudhakar touched on and to generate an appropriate higher balance, we actually assumed lower electricity rates, which in turn lead to lower self-generation adoption, and so that creates sort of an all-encompassing high scenario of what the possibilities could be, given that situation.

And then the low-energy demand case is the antithesis, essentially, of the high case. That's looking out at an economic scenario where we have low, long-term slow -- slow growth, essentially, a lower EV-adoption scenario. No climate change impacts, but yet we have higher electricity rates, which will drive down demand, as well as high self-adoption, high self-generation adoption as well.

And then kind of going back to our mid-energy demand case, as I said, it's sort of a base case assumption for the economy, but we also incorporate our mid self-generation EV adoption scenarios. And then we also include the expected climate change impacts in that scenario as well. Next slide.

So this question came up in some of our discussions with stakeholders. Essentially, you know, question in terms of: Well, we're using the June forecast of data, but given all the uncertainty out there and projections changing, you know, constantly about what the future may be, folks who wanted to know do those October -- you know, the newer vintages of data look any better, or perhaps even can we use that in our forecasts. The short answer is just given -- I mean we've seen here today the tremendous amount of work that goes into putting this together, we're getting the ball moving pretty early in the year, so by the time we get all these results, it makes it a little difficult to drop in a new set of results instead of forecast out.

But I did do a comparison of the June vintage that we're currently using in our demand cases versus the October and November data that Moody's generated. So on a statewide basis the key differences here are that the commercial employment -- essentially the employment figures are a little more severe than the data we had in June in terms of the impact that we see. You know there's continuing to be more unemployment claims coming through, so we know that it seems relatively reasonable that you would expect unemployment to be worse than what it was in June.

On the flipside of that, personal income and GSP do look a little bit better, and that's mainly being driven by assumptions around the stimulus coming in the first quarter of 2021. Obviously, as I note there, extraordinary uncertainty seems to be the phrase. I think even our Federal Chairman Powell also used that phrase. And it's really, as we know now, there's a lot of uncertainty about whether that stimulus will come through in the first quarter of 2021. we know that some unemployment benefits are going to expire at the end of the year, so things look pretty shaky, for lack of a better word around that.

And also another bit of information, you know, these outlooks, the June outlook, for example, had Covid-19 infections peaking in April. And we know not long after that June forecast, they actually peaked in July. And in looking at it now, we know we're right in the middle of potentially another peak and things could get far worse as far as infections go. But the October and November outlooks, you know, didn't expect a second wave of the virus. And they also anticipate a vaccine some time in the spring of 2021. Obviously we know that just looking at the news or there could be a tremendous amount of uncertainty around whether that ends up being the case. So I just wanted to touch on some of these differences between our vintages here. Next slide.

It's just kind of a general overview of our inputs. Obviously, like I said, I don't know if you know, our June data for the economy included, you know, essentially big shocks to employment and a severe drop in employment, income taking somewhat of a hit, and then general economic output, either manufacturing or GSP as a whole were all reduced based on Covid-19 and the subsequent economic shutdowns that occurred.

Generally there is a decline from 2019 through 2020, the obvious impacts occurring there, with the recovery beginning mid 2021 or so, and that recovery period continues through 2024, so we'd see employment that takes, you know, several years to get back up to the previous levels of employment that we saw in 2019 but generally stays below the previous projections of employment growth.

As far as demographics, we're using Department of Finance information for that. I touched on this last year as well -- or, I'm sorry -- on our last workshop, but generally population estimates have gone down, the number of factors affecting that: Low birth rates; it seems kind of morbid, but there is a slight increase in the death rate as well, we're not living as longer right now or expected to, and that will affect the household population -- or household growth as well, since those, population and household, information are linked statistics. So overall we see that -- actually I'll just go to the next slide. I actually talk about those right there, so go to the next one.

Here I'll talk about households in a little bit. So household growth has generally declined in comparison to the last cycle, which is -- we're looking at the numbers here on the statewide basis, but for all our utility planning areas we see less household growth compared to the last forecast cycle we have. So this will generally reduce residential electricity consumption overall when compared to the previous levels that we predicted.

Growth continues to be higher in inland areas compared to coastal and urban regions, and this is generally the case for the last few years, so that continues on in the data that we have here today. One side note, you know, although PV capacity -- or, sorry -- these inland areas do have more households, but, using PG&E as an example, and I'll touch on this a little bit later, you have more households in the inland regions, but you also have more PV capacity in those regions. So you initially expect that other -- just because there's more households there would be more residential sales, but it doesn't seem to be the case and it won't be the case if you have more PV capacity. So just a little tidbit there. You actually see flat or reduced residential sales in these urban regions -- or inland regions, particularly if they have large amounts of -- we're predicting large amounts of PV capacity to be put in those regions. But that's just a little -- maybe that is more interesting to me. I thought that was a fun fact that I stumbled across reading some of the data in the past few days.

We can move on to the next slide, which is just a little bit about personal income. A little graph here noting the decline in 2020. And average growth overall at 2.3 percent, but one interesting bit -- actually that should be a decline in 2020. My apologies for that. Because my -- what I was going to note is that in 2020 you actually don't see much of a drop in personal income and that's mainly because there is a stimulus assumed for 2020. We know we got some part of that stimulus but there is going to be another round in 2021, and so that would be one of the differences if I were to plot -- grab the data and plot a different graph here of the October-November-ish economic data, you would actually see somewhat of a bump up in 2021 with the new stimulus coming in. So things -- so just a reminder, Personal Income includes everything including unemployment benefits and things like that. So you would see that effect in the data here, but given the vintage that we're using to see a decline in 2021, things grow up similar to employment -- that I'll show a little bit later -- through 2024. And ultimately we end up at a level somewhat higher than our previous forecast, but generally the growth rate is a little slower.

Commercial employment will be on the next slide. Go to the next one. Perfect. So here we see the big drop obviously in employment in 2020 and then that climb through. As I mentioned earlier, as you can see here, it will take us several years to get back to those 2019 levels, but generally all three demand scenarios that we have show employment levels that are below what we are predicting before. If you look closely at 2021, that dotted red line there, our previous mid case, in those there actually is a slight dip, so things were expected to slow down a little bit. That dip is actually an increase in unemployment.

And looking at the history here, you can see there was, you know, a lead up to 2008, the 2008 recession, then a long climb and a fairly large increase in additional employment going through up through 2018. But obviously this Covid impact is slightly different than what we experienced in that recession. I think it's more likened to a natural disaster situation where you have this massive shock to your economy, then somewhat of a quicker recovery compared to the 2008 recession. Next slide.

So that was just some of the background on bits of data that we include in our forecasts, the key inputs. As I said, households, employment, and income are some of the key ones. But here I have sort of a summary of our statewide results. The little graphic on the right is our forecasting zones for California. About 20 or so forecasting zones. PG&E is broken up into six and the other territories are broken up into several forecasting zones as well covering different regions.

But generally going back to the summary here, we find that consumption is down about two percent in 2030 compared to previous forecasts and sales are similarly down.

So Sudhakar mentioned there are some changes to the PV forecast, but largely you could say it's relatively the same around 2030. So an overall reduction in consumption with a relatively similar sales forecast gives us similar reductions in both consumption and sales or -- and the PV forecast, I should say. It's a similar reduction in consumption and sales.

I have a little tidbit here about the contribution of PVs, about 14,000 gigawatt hours by 2030. We know that's also been reduced compared to 2019. It's about -- it's also going to have an effect on our overall forecast.

And the last little bullet there is the total contribution of self-generation, a large portion of that being PV, as Sudhakar presented earlier today.

Trying to check my notes if there's anything else.

Yeah. So one other thing I think is interesting to note here, we do find that overall Northern California does grow a little faster than the Southern California regions. And this seems to be related to slightly less of a reduction in household projection. So when I say it grows faster, it grows faster compared to our previous forecasts. And this is mainly due to, I believe, a reduction in our household projects. That seems to be the biggest difference there. The adjustment downward in those projections was more prominent for Southern California than it was for Northern California.

And we're also seeing in our floor space projections that Southern California also was slightly more of a downward reduction than Northern California regions. But, yeah, it's somewhat slight, but significant enough to change some of the growth rates in comparison to last year.

In the end, though, it does seem the long-term rates for the larger utilities seem to be about the same. They actually match each other very closely, and I'll talk about that a little bit later. But we could go to the next slide where I compare the consumption forecast that we have now.

So looking first at the history, you could see, you know, pretty strong growth in electricity consumption overall the state, from 2001 or so to sort of the peak of the energy crisis there and up to about 2008, where we hit that recession that I mentioned before. And so -- and then it's sort of a slow slog, not really as much growth going forward in consumption in comparison to that 2001 through 2008 period. A lot of that could be attributed to a lot of household growth was occurring at that time as well. We obviously had the housing crisis that occurred, sort of the mortgage crisis. A lot of homes were being built. That's going to be some part of that there.

And the things moving from 2008 sort of peak in 2017 or so, and we notice that you can see and we sort of dip down -- down to the 2019. Some of that could be related to -- to weather. 2017 was a relatively warm year, so that definitely has an impact on electricity consumption. But it didn't necessarily get any cooler after 2019, so we see some declines leading into the last historical year of data there.

But overall, looking at our projections here, you could see the spread between our different demand scenarios. Focusing on the mid scenario, that recovery period, we do see growth of about two percent on average through 2024. And then beyond that we sort of settle into a one-percent growth rate which is somewhat similar to our previous growth rate in our last forecast cycle, but -- over that period. But in this case our average annual growth, slightly higher than our previous forecast, and that's mainly attributed to that recovery period that's occurring there from 2020 through 2024.

Then in the next slide I'll get into statewide sales. So this is just a graphical representation of the sales forecasts overall, focusing on the mid cases. So the dark blue line at the top there is the consumption forecast that I showed on the previous slide. And then the light blue -- I think officially this is Dodger blue -- line is our sales forecast, our mid-case sales forecast. So the difference between the two is essentially the self-generation forecast, as we talked about earlier. It's the largest portion. Essentially, that -- you see a divergence between the two lines growing over time and that's essential the effect of the PV growth that we have in our forecast.

That dotted green line there is going to be our --

our mid -- our mid-mid case, so our mid demand, mid AAEE sales case. And so that is incorporating both the effects of PV as well as the additional achievable energy efficiency.

And, as I mentioned, these are the same AAEE figures as we used before. The impacts don't occur until 2020, and then you could see obviously they start growing over time as we incorporated the expected efficiency over time. But, ultimately, you know, relatively flat growth, as I said, the consumption has been slowed down, and then the sales rate ultimately gets slowed, and then the AAEE further slows the growth in expected sales in the future. Next slide.

Now I'm going to get into some of the planning area summaries. I'll cover PG&E today, Edison, and San Diego, and then LADWP and SMUD.

So PG&E is broken up into five forecasting zones: The Greater Bay Area, North Coast, North Valley, Central Valley, and our Southern Valley. So consumption here in 2030 ends up being about the same and it's mostly because there was less of a difference between our 2019 forecasts last year and our new starting point. They're basically on top of each other, almost exact. So we did a pretty good job predicting consumption for PG&E. Ultimately, sales are down because there is, you know, that PV having an effect later in the forecast.

The Bay Area is essentially still the leader and has been for a while as far as growth in energy sales. And, as I mentioned, one of the reasons behind that is residential energy sales. So in the Bay Area you're somewhat condensed and urban. You don't have a lot of roof space compared to Central and Southern Valley area where you have higher amounts of residential PV capacity and still, you know, fairly good growth in the households, but that PV capacity really brings down the sales. So ultimately you still see a higher sales growth in the Bay Area.

I have a couple notes here. Contributions of electric vehicles here, about 58, almost 59,000 gigawatt hours by 2030. PG&E by far has -- maybe not by far, but it does in fact have the most EVs out of all planning areas. It also has the most self-generation here. You can see 25,000 annual gigawatts by 2030. And the vast majority of that being PV. Next slide.

And this is a similar graph as I showed before, but -- on a statewide basis -- but for PG&E specifically, so this is just getting into the consumption forecast once again and what our trajectory looks like for our mid baseline sales forecast and the mid-mid sales forecast. You see the contribution of AAEE there in 2030, also flattening back to mid-mid or managed sales forecast quite a bit, but somewhat similar growth rates in the long term to the statewide rates. Move to the next slide, where I'm going to talk about Edison.

So Edison's consumption was down a little bit more, but this is mostly due to the fact that our starting point for 2019 is actually a little lower than what we predicted there. So ultimately we end up with long-term growth rates that are actually somewhat the same for both PG&E and Edison. Less EVs and PV compared to PG&E territory. As you can see here, and as I mentioned earlier, floor space reduction was a little larger compared to our last forecast, so we see a slightly slower commercial sector growth compared to PG&E, particularly on the recovery period. There is less of that growth in that sector. But, similar to PG&E, we do see more household growth in the inland areas but less PV by comparison, in comparison to PG&E.

In the next slide also I have a quick little graphic here. And you will notice the long-term growth rates for 2020 to 2030 are about the same, with slightly more AAEE in this case for -- for comparison.

The next slide is going to get into San Diego's territory, so similarly there was a reduction, but total consumption in 2019 was about three percent lower than our forecast, so factoring that into -- into the analysis. You know you get growth rates that are slightly different than the other two planning areas that I mentioned, but relatively the same.

The one difference here, though, is you see a slightly higher sales -- or slightly lower sales forecast in 2030, and that's mainly because you have -- as Sudhakar mentioned -- you have a lot of PV in San Diego's territory; relative to the size it's quite a bit. Proportionally it's comparable to the portion of the consumption, but similar to like PG&E, for example, so there is quite a bit of capacity there. And so that's going to lower your -- our sales forecast a little bit in comparison to the other territories.

On the next slide you could see that characterization, the growing gap between consumption and sales, and then a small amount of AAEE as well here. And we end up with like no -- basically no growth in the mid-mid case of 2020 to 2030. Things are pretty flat there. And the base case for sales is also relatively flat, only about half a percent over those 10 years or so.

The next slide is going to touch on LADWP. Similar to PG&E, where we were basically pretty close to the consumption forecast, so there's not much of a difference there, consumption in 2030 is going to be up about half a percent, not largely different. But, as Sudhakar mentioned, PV is relatively small for LADWP. As you can see there, it's only about 50 percent of the self-generation of 2030. So compared to the other planning areas, there's not a lot of growth in PV there, which makes sense. You have -- LADWP is more of an urban area. As I mentioned in talking about the residential sector, for example, in PG&E's territory is urban.

Areas that may have tall buildings that are not your typical single-family household on the in the valley, for example, so you really don't have as much in this case potentially to put PV on there, so we see that fact if you go to that slide. Unlike the other planning areas, you could see that differential between the consumption and sales actually doesn't change very much at all. It kind of follows each other pretty closely. But we do in this case have quite a bit of AAEE for LADWP, and so that brings down their mid-mid case for a slight reduction, almost flat, but a slight reduction in the baseline sales forecasting the account for the additional achievable efficiency here.

The next slide, I will touch upon SMUD. So SMUD is also going to see a downward reduction compared to our last forecast. Both the reduction is also -- you know some of it is coming from a slightly lower starting point, but a lot of this is coming from commercial, industrial section reductions for this territory. Not much of a contribution from EVs, I think. If I got my numbers straight, about -- this would be roughly a one-percent reduction compared to last year, so that definitely also has an effect on the consumption numbers. It's -- largely it's not a lot of EVs in comparison to some of the other territories and given it's a relatively small territory.

I should also note that SMUD is a part of a larger planning area that we have. It's called Northern California nonCAISO, so that includes SMUD being the largest one as well as Turlock Irrigation District and the rest of the balancing authority of Northern California, but by far SMUD's the largest utility there, so we tend to focus on them here. But, once again, yeah, the bulk of this reduction is coming from the commercial and industrial sectors and the relatively small contribution from EVs doesn't really -- has been lowered, so that -- you know, it's roughly one percent of their sales because they're relatively small, so it does have a reduction in comparison to the last cycle, a noticeable reduction.

On the next graph here, I'm just running over some of the sales numbers, comparing consumption and the baseline sales as well as the mid-mid case for our -- that includes the AAEE. So, yeah, in this case quite a bit of AAEE, 1300 gigawatts or so. That leads to just a declining, you know, managed sales forecast for SMUD. Otherwise the baseline sales forecast does continue to grow about half a percent, a little bit over that. We continue to see increasing consumption. Obviously there is -- as with the other graphs that I showed, you have this dip in 2020, a recovery period, and continued growth there.

This will be my last slide. I'm happy to take questions. I know I tried to -- there is a lot of information here and I tried to cover it as quick and as concise as I can, but I'm happy to take on any questions that folks may have.

VICE CHAIR SCOTT: Hi. Great. I don't actually have any questions. That was a lot of information, but it was very concise in how you presented it, so I'm not sure that I have a follow-up, per se, but thank you for the excellent presentation.

MR. GARCIA: Thank you.

COMMISSIONER DOUGLAS: I don't have any follow-ups either. That was really helpful. Though, that was great.

MR. GARCIA: Yeah. I apologize if I was just overwhelmed with all of it. I was tempted to get into all the specific forecasting zones, but I have half an hour, so it's really hard for me to touch on everything. But I tried to get the greatest hits, basically.

COMMISSIONER DOUGLAS: That was fantastic. Thank you.

MS. RAITT: All right. This is Heather. So it sounds like we don't have any questions. Cary, you did such a great job. Thanks for covering everything.

And we'll go on to Nick Fugate now, who is the Supervisor for the Forecasting at the Energy Commission.

So go ahead, Nick.

MR. FUGATE: Okay, thank you, Heather.

And good afternoon, Commissioners and everyone on the call. I'm going to close this session out with the presentation on the Forecast Update of Peak Results, specific to IOU Planning Areas. And I want to -- we can go to the next slide.

I want to start by reiterating what we set out to do at the update. Our forecast is a biennial process, as Cary mentioned. But because our forecasting is used in so many annual planning studies, we do these updates in the intervening years. We try to reflect the latest information on load and key drivers, any kind of projections.

We have designed this process to be streamlined relative to a full forecast year, so that in the off years we can spend our time and attention on other critical projects such as model maintenance and development and data improvements and other analysis that we wouldn't necessarily have time for in a full forecast year but that is important for supporting the next tool in IEPR.

And so our tools are really aimed at process efficiency for the update. Cary mentioned we use the econo metric models to adjust the previous adopted consumption forecast. And for the peaks we apply load profiles to translate that adjusted forecast to hourly and peak demand. And then we limit the number of load modifiers that we attempt to refresh. Next slide.

So Cary just described the update to our consumption forecast. You've heard other presenters today talk about load modifiers. So I'm going to focus on the peak forecast, and for this we use our Power Hourly Load Model. And at a high level this model works by estimating consumption profiles based on historical loads, weather, and calendar effects. We apply those profiles to the updated consumption forecast to estimate hourly consumption load. And then to determine the peak load on the system, we layer on a number of load modifiers. For example, we subtract out self-generation. We account for the incremental impacts of battery storage, electric vehicle charging, energy efficiency, demand response, climate change, and a handful of other modifiers. And each of these has different load profiles which affects the overall load profile.

And so specific to this update -- oh, you can go to the next slide -- the changes include adding an additional year of load data in 2019. It's now a historical year, which obviously updated the consumption forecast. And, as you heard earlier, our PV, battery storage, and electric vehicle forecasts have all been updated. So those impacts are now new in the hourly load model.

And if you dive into the details of the hourly results, you will see that the climate change impacts are a little different, but this is not a new analysis. This is just -- we made those incremental to the new 2019 base year. For all these adjustments, the final consumption profiles were adjusted so that the resulting system load estimates align with our weather-normalized estimates of recently-observed peak loads, annual peaks.

So this is called our weather-normalized benchmark, and then it starts with the starting point for our peak forecast. That is the focus of my -- my next few slides here. So again advance. One more.

So to develop the weather normal estimate of peak load, we begin by estimating counter-factual historical daily peaks, so basically we add demand response impacts to hourly low data that we get from the CAISO's EMS system. And this is to get an idea of what demand would be on any given day perhaps at those supply-side demand response programs.

We model these daily peaks as a response to weather and calendar effects using just the most recent three years of historical data. We use three years so that we have an update to really see what the load response is over a broad spectrum of cool, warm, and hot days. But three is enough years that we're still capturing recent trends.

And once we have modeled that relationship we use it to simulate daily peaks for an entire summer using 30 years of historical weather patterns. And from each of these 30 simulated summers, we then select the -- the peak from a simulated summer, and then -- we then have 30 simulated peaks and from that distribution we take the median and that is our weather-normalized benchmark. So next slide.

So here are the results for the process this year, for 2020, as well as a few other points for comparison. The first column is the results from our analysis last year, which was the starting point for CED 2019. The second column is our forecasted peak load for 2020, also from CED 2019. And the third column contains the recorded peaks for 2020, which you can see are much higher than our forecast. And obviously 2020 was not a normal weather year. It was much hotter than you'd expect on average.

And then the fourth column is the results of our weather normalization analysis of this year. So I do want to note that the 2020 estimates are relatively close to the forecasted value from CED 2019. And this all could be relevant when I get to a later slide. So the next slide, please.

Before I move into the discussion of the actual forecast result, I do want to talk a bit about uncertainty.

This year we have quite a lot more of it than usual and it comes in a few different flavors, each of which have different locations. So we're going to kind categorize those, the first being uncertainty, the type that Cary discussed around the extent of the economic downturn and the pace of its recovery. Some of the assumptions underlying the economic projections we're using involve the availability of federal stimulus, for example, and decisions that are going to be made by a handful of individuals. So the sort of thing that is really very highly uncertain.

But this type of uncertainty doesn't pose a particular modeling problem to us. So the historical data that we use to train our models has periods of growth and declines, so once we have selected an economic scenario to forecast to, we feel pretty good about our projections relative to that scenario.

The second flavor, however, well, the experience this year with this abrupt, large scale, and intermittent changes to patterns of energy consumption, this is much more challenging. And the staggered tools and data-collection efforts that we have in place to develop these long-term forecasts are not well suited for any type of realtime analysis. And also the problem is new and complex, and does not easily lend itself to our streamlined up-to-date process.

The third flavor is related, describing the structural changes that might emerge, might persist as we come from this Pandemic experience. This certainly has implications for a long-term forecast and so it's an important issue and certainly one that we plan to begin discussing early next year. The idea is actually planning a workshop on this topic as well as covering the economic outlook in general. So that will happen at the start of the 2021 IEPR cycle in February. So I'm excited for that.

So a couple slides ago I showed our weather-normalized peak estimates for 2020. Here we are looking at the results of the peak forecast update for CAISO as a whole, benchmarked to that 2020 estimate. And you can see, as I made note earlier, the forecast update, which is the dashed blue line, starts from a point close to the CED 2019 Forecast value in 2020. So this graph represents our standard approach to benchmarking, what we would typically do, which is to use the latest weather normal estimate of peak load. But this leads to some counter intuitive results, notably when the forecast is clearly associated with the shape of the underlying consumption forecast, based on Cary's presentation, it does not reflect the same decline in growth from 2019 to 2020 relative to the adopted forecast. So here the forecast update moves immediately into a period of growth due to economic recovery but without capturing that initial downturn leading to much higher projections in the mid to long term. Next slide.

So to mitigate this issue we have taken an alternative approach to benchmarking the peak forecast, which is to retain the CED 2019 weather-normalized estimate and bench to 2019 rather than 2020. And that is shown here in as the solid blue line. And this gives a forecast which reflects an expected load response to high-level economic drivers, everything else being equal. But of course everything else is not equal. 2020 was this unusual year, to put it mildly. And inconsistencies in the nearterm with this alternative approach are highlighted by the large delta between the forecast update and the adopted forecast value for 2020, which you will recall was close to our weather-normalized peak estimate.

So implicit in the out years of this forecast is a transition to a more normal relationship between the economic indicators, consumption, and peak demand. Now while the IEPR forecast is primarily a long-term planning tool, I do want to note that the -- there is an important near-term use case which is system resource adequacy in 2022. And in that year these results for the CAISO as a whole come in roughly 350 megawatts below the adopted forecast. Next slide.

So both of these approaches have issues, but the alternative approach of benchmarking to 2019 gives more weight to the reasonableness of the long-term forecast at the cost of close alignment to recently-observed or potentially very near-term peaks. It's perhaps helpful to think of the forecast period as being bifurcated into the two periods, a near-term period of unusual behaviors and high uncertainty that occurred and then transitioning into a period of more normalcy in the out years.

So staff believe that the alternative approach is reasonable for out years, and my remaining slides will both discuss the peak forecast update as being benched to 2019. But we're also seeking input from stakeholders as to what should be adopted and used for any near-term planning, what potential option, for example, could be to not update or to only partially update one or more initial years of the currently-adopted forecast.

So before I wrap things up, I do want to show some high-level results for individual planning areas, so go one more. This slide is specific to PG&E, but the anatomy of the next three slides is identical. The graph on the right shows PG&E planning area noncoincident peak loads, historical and forecast. The history is the solid dark gray line. The blue and orange squares show our 2019 to 2029 weather-normalized peak estimates, respectively. The dashed gray line shows the previously-adopted mid base line, mid AAEE forecast. And then the colored lines represent our forecast update for each of the managed scenarios, the mid-low and mid-mid cases being the most important for planning.

And the long-term growth rate between years 2023 and 2030 averages about half a percent annually in the mid-low case and.35 percent in the mid-mid, not significantly different from the adopted forecast, though the final result is about 375 megawatts higher in 2030, or a little less than two percent higher. And part of that, I mean it's worth noting that this is a little different than what we saw in Cary's presentation of the consumption forecast, which comes in slightly lower. And part of the reason that the peak comes in a little higher has to do with the -- again with the benchmarking even to 2019.

And for CED 2019, when we scaled the hourly model profiles to align with that weather-normal peak, we were using forecasted consumption for 2019. 2019 was a forecast year. And so this year, when we are doing that scaling we have the actual load for 2019, which, as Cary mentioned, came in lower than our previously-forecasted values. And so the peak-to-energy ratio in that base year is actually higher as it impacts these -- this forecast update.

And so also PV -- I'm sorry. So by 2030, electric-vehicle charging across all vehicle classes adds about 355 megawatts to the peak hour load in the mid-mid case, while behind-the-meter storage is projected to decrease that load by about 285 megawatts.

PV is expected to reduce load by about 640 megawatts during the 2030 peak hour, and this is unique to PG&E. Both SCE and SDG&E are projected to peak in early September, but PG&E peaks in July and so still has a little bit of solar production even during the peak hour, even as it shifts to hour 19. Go to the next slide. I think we skipped one. Perfect.

So for the SCE planning area, the mid-low forecast grows at a rate just under.3 percent annually beyond 2023, so calculating growth based on sort of this period from 2023 to 2030, after the -- after the economic recovery. In the mid case there is very little growth on average, so growth does take up at the tail end of the forecast after the shift to hour 19, when at that point adding incremental solar doesn't reduce your peak load any longer.

And the mid-mid case ends up at about 145 megawatts higher than the adopted forecast, or just over half a percent. By the end of the forecast, electric-vehicle charging adds 445 megawatts during peak hour, while storage reduces load by 205 megawatts.

And for the -- go one more slide -- for the SDG&E planning area, the mid-low and mid-mid cases grow at about.7 and.4 percent annually after 2023. And in the mid case, a little under 50 megawatts lower than the adopted forecast by 2030, comes in at about 50 megawatts lower by 2030, or that's about one percent. Also in 2030 electric-vehicle charging adds 120 megawatts to the peak hour and storage reduces its load by -- reduces that peak hour load by 110 megawatts. Next slide.

So the tables in my previous three slides showed the timing and magnitude of the noncoincident planning area peaks, but for certain planning efforts the coincident peak forecasts are also important. So I've included this slide mostly for reference. In the near term, utility-specific coincidence factors move around a bit as peak shift occurs in different years for different utilities.

And things sort of settle down toward the end of the forecast, though, when enough PV has been added in every territory to peak hour, hour 19 across the board. Next slide.

So the results presented here today, they have been at a relatively high level, a lot of detail, but still at a high level. And we recognize that, you know, many of our stakeholders are interested in seeing quite a bit of granularity, so immediately following this workshop we will begin docketing additional data files that contain our forecast results in much more detail. In terms of the peak forecast, this will include annual and monthly coincident and noncoincident peaks by planning area and for the CAISO as a w whole. So you should begin seeing those files tomorrow.

And we also want to be available to answer any questions or have further discussion since folks review our proposed forecast update, so please feel free to reach out to me or to any of our presenters with questions or to set up a call.

Our formal comment deadline, I think this was mentioned at the top, but it's close of business December 17th. And we are planning to ask the Commission to consider adopting our final results at our January 13 Business Meeting.

And then we will be right into the next IEPR forecast cycle, so keep an eye out for that workshop in February, covering economic outlook and potential structural changes to transportation, business, consumer behavior, etc.

And another shout out to Nancy Tran for spearheading that effort and Omar. Yeah, that's it. So with that I'd like to thank everyone for their time and attention today. And if there are any questions, I'm happy to address them.

VICE CHAIR SCOTT: Hi, Nick. I do have a question. I'll jump in. I was wondering if you could just briefly reexplain, so kind of back on slide 7 of your slides, you were talking about the normalized numbers that we have for the different peaks and that if they were very high in the summer because the summer was so warm, there may also be some incidences where we're seeing that they were different than we anticipated because of Covid. Can you explain again how you are capturing that within the forecast?

MR. FUGATE: Sure.

Can we pull up slide 7, by chance?

VICE CHAIR SCOTT: Oh, yeah, so what we were looking at was kind of the normalized values versus what we forecast versus what was actual. And I just wanted to understand again how we're capturing that within the forecast or maybe it's something we end up writing up in the text, or something, but I was just -- if you could explain that one more time, that would be great.

MR. FUGATE: Right. So the actual peaks, that third column, that was we actually -- if you were to go to the CAISO's website and download their load data, what I'm talking about is these are the actual recorded system peak loads.

VICE CHAIR SCOTT: Yes.

MR. FUGATE: And those are -- those are much higher than you would expect in a normal year because it was so hot. And so we normalized those according to the process I described on a previous slide to get a more reasonable kind of starting point for our peak forecast, because the peak forecast is so weather sensitive. And so we don't want to start the peak forecast from -- from the previous year's actual peak load because -- you know, and last year was really hot, then you're going to be starting from a really high place, and your forecast will be much higher than you would expect normally.

So we always benchmark our peak forecast, which is an elaborate scaling process, to bring the forecast -- the forecast starting point in line with our most recently normalized peak load estimate, so in this case that would have been the 2020 normalized peak estimates here in that fourth column.

However, -- and maybe it would be better to advance this slide. Sorry, one more. Yeah. So however when we -- when we do that, when we benchmark to the 2020 value, essentially we're -- we're benchmarking, we're scaling our forecast so that the 2020 forecasted value aligns with the 2020 weather-normal value, right. And the 2020 -- the 2020 forecasted value does not include -- so the 2020 forecast -- the 2020 forecast value of consumption, which heavily influences the peak, does not -- if you were to compare the -- actually advance one more slide. I'm sorry.

So you can see on the solid blue line from the 2019 value to the 2020 value, there is a significant drop in the peak forecast from 2019 to 2020, and this is due in large part to the decline in -- or the decline in consumption due to the depressed economic indicators. So if we were to take -- so given that and given that the 2020 weather-normalized peak value did not experience a significant decline relative to 2019, if we were to bench the 2020 forecast value to the 2020 weather-normalized value, that sort of gives us this dashed line, right, it's essentially shifting the whole forecast up so that the 2020 value aligns with the 2020 weather-normal estimate.

But you know 2020, the relationship between consumption and peak was quite different due to Covid. Right, we had a decline in consumption, particularly in a lot of specific months, but our -- you know we didn't see a significant decline in peak loads in the summer or a temperature response to -- or a load response to temperature in the summer, so our weather-normal estimate of peak load was not that different in 2020 even though consumption was quite different this year. And so --

VICE CHAIR SCOTT: Okay.

MR. FUGATE: -- so that's -- that's -- I don't know if I have clarified things or confused it even more, but...

VICE CHAIR SCOTT: No, no, no. I think it's really helpful. Just for me, it was something that I heard you say it the first time through and I thought let me hear that a second time because I feel like it's a really important point to understand within the forecasting, because it wiggled down a little bit because of Covid, it wiggled up some because there was a really hot summer, and then kind of how do we capture that and normalize it so that we have a good, solid forecast of course, but then, you know, folks are using for planning and all of those other things. So I appreciate the second walk-through there.

MR. FUGATE: Sure.

VICE CHAIR SCOTT: That's the only question that I had. I don't know if other Commissioners have questions or not. Thank you for the great presentation.

MR. FUGATE: Thank you.

VICE CHAIR SCOTT: It's very quiet and I know we're not a shy bunch, so I would --

MS. RAITT: Yeah. This is Heather.

VICE CHAIR SCOTT: -- turn it back to you or to Heather.

MS. RAITT: Okay. So I do think, Matt, looks like we have a question on Zoom if you want to go ahead and...

MR. COLDWELL: Yeah, so.

MS. RAITT: ...thank you.

MR. COLDWELL: Yeah. So thanks, Nick, for the presentation. Just have one question in the Q and A box here. It's from Song-yi, hopefully I'm pronouncing that correctly, from Southern California Edison. The question is: The weather-normalized 2020 estimate is lower than 2019 and compared to our estimate. Is there any significant weather assumption change?

MR. FUGATE: Any significant weather assumption change?

MR. COLDWELL: Right.

MR. FUGATE: I'm not -- I'm not quite sure how to interpret that question. I mean the changes that would have happened, so we would have added the 2020 load, the 2020 load -- the 2020 loads to the three-year rolling window and it would have dropped 2018. So to the extent that the temperature response in 2018 -- or the load response to temperature in 2018 was slightly higher than 2020, then that could account for some of the decline. But if it's -- if it's a departure from Edison's estimates, certainly we can set up a colloquy, I'd be happy to discuss their analysis as well.

MR. COLDWELL: Great. Thanks. So as you were answering that question another one came in: Could you please summarize the primary drivers behind the higher, long-term projections of PG&E, noncoincident peak in the 2020 mid -- in the 2020 mid-mid relative to the 2019 mid-mid? In other words, if the higher actual 2020 peak load, then forecasted from CED 2019 has not played a key role in that, please identify the remaining drivers.

MR. FUGATE: Right.

MR. COLDWELL: I can read that -- I can read that again if you need me to.

MR. FUGATE: Yeah. No, I'm looking at it. So I did try to kind of explain that and I will try again. So, as Cary noted in his presentation, the actual consumptions -- so when we forecasted peak for CED 2019 we went through the same benchmarking to the 2019 weather-normal peak. But we were using -- we were using a consumption estimate for that year that was a forecasted value. And so when we are doing it this year, we are using the actual consumption data that we have now that we didn't have last year, which is a fair amount lower than it was last year. And so the peak to energy -- the peak-to-energy ratio in that -- in that base year is higher than what we used in CED 2019. But when you look at the actual growth rate over the long term, it's not significantly changed from -- from CED 2019. It's just the kind of peak-to-energy ratio implicit in the newly-scaled load profiles.

MR. COLDWELL: Great. Okay. Thanks. That's all the questions we have in the Q and A box, so I'll turn it back over to Heather.

MS. RAITT: Great. Thank you, Nick.

Thank you, Matt.

So that means that we're ready to go out of the public comment period. And so again you can -- if you're using Zoom from electronic device -- you can click the raised hand function to let us know, icon to let us know that you'd like to make a public comment. I see a couple of hands raised. And if you're on the phone, press star 9. And RoseMary Avalos from the Public Advisor's Office is here to help us.

Thanks, RoseMary.

MS. AVALOS: You're welcome, Heather.

I will first call on attendees using the raised hand feature on Zoom. And then please state your name and affiliation, and spell your first and last name. Also please do not use the speaker phone feature because you may not be able to be heard clearly.

Okay. Ranjiv, and your line is open and you may need to unmute on your end. Go ahead.

Ranjiv? And the name is spelled R-a-n-j-i-v.

Okay. Well, I'll move on to the next raised hand, and the initials are RG. Please state your name and affiliation and spell your first and last name for the record. Your line is unmuted. Go ahead.

Okay, go ahead. RG?

Okay. I'll go ahead and move on to the phone line. And, just a reminder, to raise your hand you would dial star

9 and then to unmute, star 6. So is there anyone on the phone line that would like to make a comment?

Okay, I'm going to go back to RG. I still see the hand raised.

RG, do you want to make a comment?

Okay. Seeing there are no raised hands, I will turn to Commissioner McAllister.

MS. RAITT: Looks like we're done with public comment. I don't know if Commissioners would like to make any closing remarks.

VICE CHAIR SCOTT: Well, I'll jump in and make a closing remark. This was, I think, another data-rich, chuckfull afternoon with getting the updates on the forecast, everything from energy storage straight through to understanding how the hot summer impacted our -- and Covid impacted our forecasting. So I just want to say thank you so much to our entire team for their expertise and on putting this together and the excellent presentations. I thought it was a lot of really good information.

It is data heavy, but they presented it in a way that I thought was really clear and understandable. And I'm sure that members of the public appreciate that just as much as I do, so a big thanks to the whole team. And maybe I'll turn it back to Heather to remind folks when the comments are due, although I know she's done that and we'll call it another excellent day.

MS. RAITT: Excellent. And I also just say this is our last Workshop for the 2020 IEPR Update, so thank you, everybody. And I just want to do a quick shout out for our excellent student assistant Harrison Reynolds. This is his last day with us, but he -- we're happy to keep him at the Energy Commission working as a full-time staff person, so congratulations to Harrison, and we're going to miss you. So thank you for that little shout out and indulge in that.

But public comments are due --

VICE CHAIR SCOTT: Absolutely. Let me say congratulations to Harrison as well. That's awesome to hear.

MS. RAITT: Yes. And so -- but back to our Workshop, our public comments are due on December 17th, and always happy to get those written comments, so, and also, as Nick offered, if you want to reach out to staff directly in the meantime, we welcome that too. So I think that's it. Thank you, everybody. Bye.

(Whereupon, the Workshop was adjourned at 3:54 o'clock p.m.)

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I DO HEREBY CERTIFY THAT THE TESTIMONY IN THE FOREGOING HEARING WAS TAKEN AT THE TIME AND PLACE THEREIN STATED; THAT THE TESTIMONY OF SAID WITNESSES WERE REPORTED BY ME, A CERTIFIED ELECTRONIC COURT REPORTER AND A DISINTERESTED PERSON, AND WAS UNDER MY SUPERVISION THEREAFTER TRANSCRIBED INTO TYPEWRITING.

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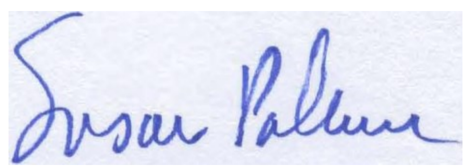
IN WITNESS WHEREOF, I HAVE HEREUNTO SET MY HAND THIS 21ST DAY OF JANUARY, 2021.



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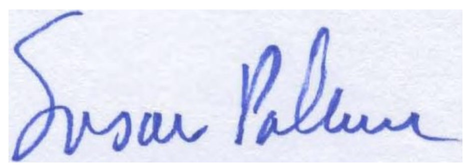

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