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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of:	)	Docket No. 19-IEPR-03
	)	
2019 Integrated Energy Policy Report	)	RE: Electricity and Natural Gas Demand Forecast
	)	

IEPR COMMISSIONER WORKSHOP ON THE

2019 CALIFORNIA ENERGY DEMAND PRELIMINARY

ELECTRICITY AND NATURAL GAS DEMAND FORECAST

WARREN-ALQUIST STATE ENERGY BUILDING

1516 NINTH STREET

1ST FLOOR, ARTHUR ROSENFELD HEARING ROOM

SACRAMENTO, CALIFORNIA 95814

THURSDAY, AUGUST 15, 2019

10:53 A.M.

Reported By:

Lucien Newell

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Other Presenters

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Sean Hernandez, Southern California Edison

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P R O C E E D I N G S

AUGUST 15, 2019 10:00 A.M.

MR. FUGATE: Okay, thank you, everyone. Again, sorry for the delay. Appreciate your patience. We're going to go ahead and get started.

Welcome to today's 2019 IEPR Commissioner Workshop on the Preliminary Energy -- California Energy Demand Forecast.

I'm Nick Fugate with the Energy Commission's Assessments Division. And I'm going to run through a few housekeeping items real quick.

Restrooms are in the atrium, out the door and to your left. If there's an emergency and we need to evacuate, please follow staff to Roosevelt Park. It's directly across the 9th and P intersection.

The workshop is being broadcast through our WebEx conferencing system, so just be aware that everything is being recorded today. We'll post the audio recording to the Energy Commission's website in about a week, and the written transcript in a month.

At the end of the workshop, there will be an opportunity for public comments. We're asking parties to limit their comments to three minutes. For those in the room who would like to make comments, please fill out a blue card and give it to me. And when it's your turn to speak, please come up to the center lectern and speak directly into the microphone. It's also helpful if you can identify your name and affiliation for the record. And if you have a business card, please leave it with our court reporter.

For WebEx participants, you can use the raise hand feature and we will call on you during the comment period.

Materials for this meeting are available on the website and hardcopies are on the table, at the entrance.

Written comments on today's topics are due in two weeks. That's Thursday, August 29th. The workshop notice explains the process for submitting written comments.

And, finally, I'd like to thank everyone for being here today. I'll remind everyone, one last time, if you're speaking, please identify yourself for the record.

And with that, before we begin our presentations, I'll turn it over to the dais for any comments.

COMMISSIONER MCALLISTER: All right. Thank you, Nick, appreciate it. Again, really appreciate everybody's patience. It's a very rare occurrence, actually, that we start late. Usually, we're right on time. So, apologize for that.

My name's Andrew McAllister. I'm the Lead Commissioner on energy efficiency and energy assessments, and looking at, and leading the forecasting work this year.

And a lot is going on with the forecasting. I'm going to be brief, actually, so we can kind of make up a little bit of time. One thing I wanted to say, we still will stop at 11:45 and we still will pick up ag 1:15. I have to be in the capitol building from noon to one. So, that we'll just go as far as we can until 11:45, and then pick up at 1:15.

So, obviously, the forecasting is bread and butter for the Energy Commission. At the same time -- you know, we've been doing it for a long time, but at the same time there is a lot of innovation happening in this space. We're firmly in the digital age. We have access to a lot more data than we ever have. And we also need a lot more information than we ever have needed to be able to do forecasting in this new, complex energy environment that we're in today. With distributed energy, with all the great technologies, with really looking to a much diverse set of resources, most of which are distributed or many of which are distributed. And looking at how we can anticipate what's coming in a much more robust, and localized, and increasingly temporal way.

So, our forecasting kind of to-do list gets bigger, even as we have all these tools to help us answer a lot of these questions.

So, you are all part of this discussion and we need your creativity and vision, as well, to inform what we're doing. And, you know, we realize there's an audience for this forecast that has to digest it and use it, and including across the other agencies, the PUC, and the ISO, and many other folks outside of this building.

So, it really is a big lift, with lots of participation. At the same time, it's a little bit, you know, for the uninitiated, a little bit obtuse and a little bit of a foreign language. So, our effort with these workshops is to not have it be insider baseball as much as possible. And really, try to have a conversation that is informed by as many stakeholders, as many knowledgeable stakeholders as possible, so we can have a product that really stands up over time.

And so, there's the forecast itself and then there's the methodology. And at the same time, we're doing the forecast this year, we're also thinking about the methodology and how that's going to evolve going forward. And so, there are multiple sort of layers to this. I think probably more so this year than perhaps in the past.

We have a great team on this, who will, in their turn speak, and I have a lot of confidence in the work that they're doing. And, hopefully, that will come across in the presentations.

And your comments, coming in to help inform the next steps, are equally critical. So, really appreciate everyone coming today, both here in the room and online. And really looking forward to comments and insights along the way as we proceed through this year's forecast development.

And I want to thank Nick and the team. I see Cary, and Chris, and the whole team here with us, and you'll hear from them in turn.

And then, in the afternoon, the utilities and their individual presentations and contributions.

So, I'm grateful to be joined by Rhetta deMesa, Commissioner Janea Scott's Advisor, who is -- I think Janea is the Lead Commissioner on the IEPR overall this year, and couldn't be with us today. But we have Rhetta in her stead. So, Rhetta, do you want to make any comments.

Okay. All right, well, I think we're ready to back to you, Nick.

MR. FUGATE: Okay, thank you. I'm going to kick things off with a short presentation on just the purpose of the forecast and the preliminary forecast.

So, the forecast lays the foundation for a number of State-sponsored planning activities. At the CPUC, it feeds into the integrated resource planning process, distributed resource planning, and also informs the Resource Adequacy Program.

At the ISO, it informs transmission planning and flexibility studies. And, importantly, it provides important information for setting and tracking progress toward the State's energy and climate goals.

So, the reason we do a preliminary, you know, it's a sort of check in with stakeholders. It's a first look at the impacts resulting from a new set of inputs, assumptions, and modeling changes. It also gives us an opportunity to compare our forecast against the most recent utility forecasts that we have, that are submitted through our IEPR Demand Forms every two years.

You know, the forecast feeds into other Energy Commission assessments of electricity and natural gas systems. So, it's important for us to produce this preliminary forecast so that the results from those dependent processes can feed back into our revised forecast in the form of, for example, new rate projections.

And we leave enough time between the preliminary and the revised forecast such that we can make changes for the revised based on discussions internally, and with stakeholders.

So, we do produce a forecast of natural gas end-user consumption. Our focus today, though, will be on the electricity demand forecast, and user consumption, retail sales, annual and monthly peaks, and hourly demand. Our base here for both sales and peak will be 2018. And the forecast period extends through 2030.

We're presenting here, today, only our baseline forecasts or forecasts that account for committed standards and program impacts. We have some discussion today of additional achievable efficiency, AAEE, but that will be focused on our process for developing those scenarios, rather than on actual results.

I will note that there are a few components of what had previously been considered additional achievable that are now part of our committed assessments of efficiency.

Some program impacts in federal appliance standards, but perhaps most notably, the 2019 Title 24

Building Standards are now on the books. And so, for this cycle, we won't be developing any AAPV scenarios. those compliance-driven, system adoptions are now going to be part of the baseline.

To develop the 2019 preliminary forecast, we conducted a full set of model runs. We refreshed our rate projections and economic drivers. We've incorporated another year's worth of historical load data, system interconnection date, and forecast data provided by load-serving entities. Which, among other things, give us further insight into the CCA landscape over the next two years.

We've developed new projections for important load modifiers, such as electric vehicles, self-generation, and committed efficiency.

And we've begun incorporating results from our load-shape project with ADM. Our hourly model, for example, now incorporates new electric vehicle charging profiles.

And as part of our effort to provide more localized forecasts, we incorporate information that may have a significant impact on future load for smaller LSEs. For the preliminary, this includes our forecast for Valley Electric Association, which we adjusted to account for sizeable planned cultivation facilities that are not captured in our previous forecast.

For the revised, we'll be refreshing our drivers again, make sure that we have the latest economic projections. DOF, the Department of Finance, will providing a new household forecast and we'll update our rate projects again.

By the start of October, we'll have recorded our summer peak for 2019, so we'll create a new weather-normalized starting for our peak forecast.

Over the next couple of months, our efficiency team will be developing AAEE scenarios. And so, by the revised, we'll have a new set of managed forecasts.

Expanding on a 2017 staff analysis of potential energy impacts from cannabis cultivation, we plan to include projected impacts in our 2019 revised forecast.

And there will be some modeling enhancements. Some, as our presenters today will discuss, are the results of ongoing work. But others may arise in response to stakeholder comments and discussions following this workshop.

And, lastly, I want to acknowledge that some stakeholders have expressed an interest in including impacts of fuel substitution in the forecast, perhaps by utilizing our additional achievable framework. This is clearly a reasonable and likely necessary objective, given State goals around building decarbonization. But there's a great deal of uncertainty around the range the potential decarbonization strategies that could play out.

AAFS would be a particularly complex piece of analysis, one that would have to be reconciled with our efficiency impact analysis with our hourly modeling work, and with our end-use models.

Similar to AAEE, we would have to translate AAFS impacts to specific loads buses, though right now we have no data on the schedule and location of potential retrofits.

And so, for these reasons, we will not be developing AAFS for Commission adoption as part of the 2019 IEPR cycle. Instead, we're proposing to present, alongside our revised forecast, a preliminary analysis of potential AAFS impacts. Importantly, this analysis would outline additional data and analytic issues that need to be overcome before AAFS is ready to be adopted.

At the revised forecast workshop later this year, will likely be a venue for this discussion.

Which brings me to my last slide here, some important dates. These are the anchor points for the remaining forecast schedule. August 29, written comments are due in response to this workshop.

September 26 is a workshop we have planned for emerging topics related to forecasting. December 2nd is another workshop where we will present and discuss our revised forecast. And January 2020 is, whatever the business meeting date ends up being for that January will be when we're planning to present the forecast for adoption.

And so, unless there are comments from the Commissioner, I'll invite our second speaker, Ingrid Neumann, to discuss additional achievable energy efficiency.

MS. NEUMANN: Hi. I am Ingrid Neumann and I will be presenting on additional achievable energy efficiency, specifically on the process, like Nick mentioned, as we are then designing the scenarios and we'll have some numbers in October, and the final numbers in November. So, more about that at the end, but let's talk about the process, first.

So, for those of you who don't know, additional achievable energy is an hourly load modifier to the baseline forecast, so that's the context here for the demand forecast.

So, before I go into that process, I wanted to mention what the difference is between SB 350 and AAEE, because we do use a lot of the same data streams, but they have very different goals.

So, like you can see on the slide, SB 350 projections are used to identify whether the potential of programmatic targets achieve the doubling goal that was set by the Energy Commission. So, that's the goal to double the energy efficiency from 2015 by January 1st of 2030.

Now, AAEE projections are actually incremental baseline -- or, incremental to the baseline demand forecast and serve for resource planning and procurement needs. So, this is always forward looking and it's specific to modifying the demand forecast.

So, SB 350 is fixed to a 2015 base year and you're always measuring with respect to that. Whereas, the AAEE, as I mentioned, is always forward looking, so it has a rolling base year that rolls forward each IEPR cycle.

For the uncertainty, SB 350, the first time it was measured was in 2017 and there was only one scenario for it. So, there was only one item there. But for 2019, we've added some capability of having different options or different scenarios, if you will, for SB 350 projections. So, you'll see that in a separate proceeding.

So, AAEE, as you know, does have a very elaborate process of scenario design, which condenses the uncertainty of specific elements into scenarios that range from being conservative to much more optimistic.

So, some agencies use SB 350 as a proxy for a very high-efficiency scenario. But for AAEE, we actually have explicit agreements to use specific scenarios for resource planning and transmission planning studies. So, there's an end consumer at the end.

So, the implications of falling short of the targets, that's something that only applies to SB 350, because we want to see how we're doing with energy efficiency with respect to the goals that were set for SB 350.

So, now, let's put our lens completely on AAEE for that process. And I wanted to -- before I show you the flow chart for that, I want to highlight some process improvements that we've made from the 2017 IEPR cycle to the 2019 IEPR cycle.

So, we've improved the analysis of decay and re-participation. This is for all of the data streams that are being used. We are using cumulative results from the IOU/PG study for IOU program savings. So, we have the -- we retain the same decay and replaced rates that are used in the PG study there.

Similarly, for the POU model, we retain those decay and replace rates. And what we've done for this cycle is we've actually added some more capability to having not just the one scenario that's reported in the CMUA report, but have more conservative options, so we can actually have variation in the scenarios. Also, for the POU programs. We didn't have that before.

Then, we've updated and expanded the Beyond Utility Program workbooks that were originally developed in the last SB 350 cycle. And the workbooks are embedded in a new tool that assigns end-use level decay based on EUL. We have a total of 20 workbooks, now, including fuel substitution. It's very limited for new construction, so I wanted to say that in context with what Nick had spoken about previously.

Then, conservation voltage reduction and we added workbooks for the agricultural and industrial sectors. So, we're capturing more areas of savings.

And then, we have improved attribution to sector and end use. This is very important because as we developed the new hourly tool for AAEE, because it is an 8760 hourly load modifier to the baseline forecast, we want to have, by the specific end uses, the correct or the most correct mapping to the new load profiles that we have available to us.

So, we are creating 8760 hourly projects from annual AAEE savings for the 10-year forecast period.

And last, but not least, we are improving the natural gas demand analysis because building decarbonization is an emergency --? Well, an emerging is what I'm trying to say, but there are those that, you know, we need to think about building decarbonization. So, it is a policy emphasis and that would have us refine our gas demand analysis.

All right, so here is the beginning of our flow chart. We have three main data sources. The first being for the CMUA PG study, for the POU projections. And these are for their program projections.

And the second being the IOU program projections, found in the CPUC's PG study that was recently, or release this year.

And then, lastly, the Beyond Utility Programs, which are captured in these workbooks in-house.

So, all of those projections need to be created into AAEE scenarios. Right, there's not just one number there that we'll have. So, we need to look at the POU projections, and we've created to have a capability of having some variation there, so that we can build those scenarios being conservative to optimistic.

And, similarly, as we did in 2017, we will do the same thing for the IOU program projections.

So, within the tool that we have created, that handles the workbooks, there is also a capability of designing AAEE scenarios for the Beyond Utility Programs, so that's in here. So, everything becomes the six AAEE scenarios that we will have.

And there's some added intricacy as far as codes and standards. So, codes and standards we get -- so, this is Title 20 appliance, the federal appliance standards, and Title 24. We get contributions from the PG study, from the IOU PG study, as well as future code cycles that are not captured there in our Beyond Utility workbooks. So, that's what that up and down arrow is showing us. That we need to make sure that we capture everything once, you know, and that there is some interaction.

So, you know, it could be three data streams or four data streams that all need to come together as six scenarios for each piece, for each of those elements, and that goes into this master scenario. And that's the scenario design.

So, this is all by utility, by sector, by end use, and then for each of the six scenarios. And, also, it's for electricity demand, as well as natural gas demand. And this is on an annual basis.

Now, the electricity demand is then further fed through this hourly tool that we've developed and will give us also by sector, or end use, and by scenario 8760 results for each hour in that ten-year forecast.

All right. So, since we have completed one cycle in 2017 recently, right, we are really repeating the same type of process with the added refinements that I mentioned in my first slide. So, I wanted to show you what a complete grid might look like with all of the scenarios developed.

So, we're starting here with the final 2018 CPUC PG study. So, these are the five scenarios that were presented in the PG study from the last cycle. Now, one of those is adopted by the CPUC as the goals for the IOUs. And that's the scenario that we use in the middle and build our scenarios around.

So, we would take that grid and fill in more conservation options using all of those levers in that colored bar. Right, we have, you know, building stock, retail prices, you know, different program assumptions that we would work with the IOUs and the CPUC with in order to determine what variation is feasible there. And then, as well as cost-effectiveness threshold that can be made more lenient or more stringent, depending on if we want a more conservative or optimistic scenario.

So, this was how it was filled in for the last

IEPR cycle, for the IOU contributions. So, that's for the programs. But then, you might be able to see, I don't know it's very small, and the details are dreadfully important for today's discussion because these are from last time. But the bottom bar shows us that we need to eliminate any duplication with the baseline forecast. Right, because we are trying to modify the baseline forecast, so we don't want to count anything twice.

So, if you're looking at, you know, some of the shading, it's not quite as nice here, right, we would need to subtract that out so that we count everything only once. Okay.

So, then, the bottom bar of the scenarios here are the codes and standards that are captured in the Potential and Goals study. So, we look at those. We can have different compliance rate reductions. We can have enhancements to that. We can include various code cycle vintages, or not include them, depending on what's appropriate for each scenario.

So, we do take those IOU attributable savings and they are scaled up to total savings. And then, we additionally, because we don't just want savings for the IOU territories, but for the entire State of California, we then scale to statewide savings and allocate the shares based on electricity sales to the POUs, and POU groupings. This is actually very important for the small POUs that reside inside the CAISO SERFs or the CAISO planning area, which is important for, you know, resource adequacy and planning needs from that source.

So, this one bar here, you might not have seen before because this is the one POU AAEE scenario that was used last time. So, the POUs, for their program potential savings, they submit in the CMUA report one option. So, we didn't build around that option, we just used that one option for each of our six scenarios.

This time, we have the capability of building around that, similarly to how we did that for the IOU programs.

So, then, we move on to Beyond Utility. That could stack down, but then it just gets even larger. So, I promise there is a slide in a couple of slides ahead that has everything in its full glory.

So, for the Beyond Utility workbooks, we do kind of tend to separate those into Beyond Utility Programs, and then the actual codes and standards savings. So, this top bar is the codes and standards savings. We want to consider only codes and standards future ratchets that are not already captured in the PG study and, of course, that aren't the baseline forecast.

Right, it's all about capturing it exactly once.

So, everything is scaled to statewide and allocated to the utility territories. And again, you're careful to eliminate any other duplication.

So, now we are here for the 2019 IEPR cycle and we propose to do very much -- use a similar framework. So, this is, what's filled in is that mid-scenario, which is the scenario that the CPUC is looking at for IOU goals. Right, so we would build around that, make more conservative estimates, as well as make more optimistic estimates. So, we haven't filled that in, yet. So, you have opportunity to comment on that, if you like.

So, we have the same types of levers that we can tweak, right, for the programs, for the cost effectiveness, for the econ demo models, and such.

Again, we're looking at the codes and standards, taking a portion of that from the PG study, and scaling it up so that you get total savings for each of the territories, be the IOU or POU.

And, then, we have the POU scenarios, which are new this time. We are able to build around that one reference. I mean, there aren't as many levers for this as there are for the IOU scenarios, but there are some levers where we have an expanded measure list. We can increase and decrease incentive levels. And, you know, decide on what's appropriate for the retirement of programs and that sort of thing. So, there are some variations that we can build scenarios around.

And then, lastly, for our in-house effort, we've had a very large contractual effort for the Beyond Utility workbooks this cycle. The workbooks were originally developed for SB 350 purposes because we were trying to capture all energy efficiency savings possible.

Right, but in doing so, we realized that some of this is appropriate to include in the demand forecast, as well, as AAEE modifies the baseline. So, that's what we will be looking at doing more of.

Right now, the inputs are loaded to the maximum savings potential, so they're very optimistic because they are to measure progress towards the SB 350 savings goals.

And then, as a reminder, if you did look at the 2017 IEPR cycle, for the Beyond Utility that was included in 2017, only Prop. 39 was included in the first five scenarios. Only in the last, in the sixth scenario, the high plus scenario, were some of the other program workbooks included, and at discounted rates. So, they were scaled down from that maximum savings potential for inclusion in AAEE.

So, we would be looking at what -- you know, how do we include or how much do we include for each of these programs, in each of the scenarios based on how conservative or optimistic that scenario's intended to be.

So, the workbooks do vary in level of sophistication, but they all have various savings parameters that can be adjusted. So, we do have quite a bit of flexibility using low, mid and high IEPR econ demo drivers. There are conservative reference, aggressive and aggressive savings estimates defined for each program, and individual workbooks. And then, we can have an individual weight assigned to the program workbooks included here.

So, those program workbooks, the 20, right, are listed here. The codes and standards work a little bit differently. They have a little special line. But it gives us an idea of what kind of flexibility we might have. So, I'm giving you a visual representation of how one might pull some of those levers here.

So, for Title 24, for example, you can decide at which year, so which code cycle you end the inclusion at. So, you could include only through 2022, or you could include through 2025. You know, which of those code cycles do you include up to?

Then, you can do this differently for new construction, as well as for additions and alterations. And then, of course, for the residential and commercial building sector you can have those levers be different. So, similarly, you can do this for Title 20 and the federal appliance standards.

All right, so here it is in its full glory. We do have both the IOU potential program savings and the codes and standards savings for the blue and the pink bars are coming from the PG study. And then, there are additional codes and savings in the Beyond Utility Program Savings as part of those three workbooks that exist in there. And then, we have the POU potential program savings.

So, this is what we would fill in for our final scenario definitions, when we have the six AAEE scenarios for this code cycle.

So, all of that, in that box, goes over to the right-hand box that's boxed in orange. And so, that's our whole scenario design process and then we could run all of that through the hourly tool.

So, a little bit more on the hourly tool. We've mapped the 48 named end uses to the new ADM load shape profiles, and we've supplemented that with Navigant load shape profiles using the 2017 forecast, where needed.

The input menu for this tool allows selection of forecast start and end year, so it's somewhat future proofed in that way because, of course, there's a rolling date for those ten years.

And then, the utility IOUs, the main POUs, and then for the small POUs we have them in north and south groupings. So, put output out by utility and then you and select, if you wanted, just at the sector level or if you want full sector end use level, 8760 for electricity, for all ten years of the forecast.

And you can also include or omit transmission and distribution losses. And as I mentioned, the outputs are 8760 hourly results for each scenario, for each forecast year.

So, our schedule is aggressive, right. We're working very hard. Formal comments, as Nick mentioned, are due on the 29th, but the sooner you get them to us, it is appreciated, right, as we are working.

The September 26th, there's another IEPR workshop on emerging issues. And we'll put our AAEE scenario designs as a portion of that. So, that's the first time we will be able to present those scenario designs and take comments on those. But if you have comments on how you might think that we ought to do it, that's also helpful at this point.

And then we, the first time we'll have hourly results internally will be October 1st. And then, we're giving ourselves a month to clean those up, take your comments into consideration further, and have those to the forecasting unit to modify that baseline demand forecast.

So, questions or comments?

COMMISSIONER MCALLISTER: Thanks, Ingrid, that was great. So, you know, we do briefings regularly on this, so I don't have a lot of questions. I do want to talk about a couple things, though.

So, you know, Nick talked about how, you know, we're not quite ready to do AAFS in fuel substitution. You know, we're gathering tools and data, and I think that's a reasonable thing going forward. I think stakeholders are really going to want to talk about that and, rightly so, you know, it's kind of a hot topic and it's necessary going forward.

And I guess I'm wondering sort of in that realm, you know, there's a bunch of things. There's a lot going on at the PUC, in particular, about this. And on the one hand, you know, the portfolio, sort of I think there's a staff paper out right now that sets goals going forward for the new portfolio that will get discussion. A little bit of shifting between programs and codes and standards savings.

And then, there's also the recent decision on the three-prong test. And so, there's a lot of discussion about how the portfolio funds will -- you know, the traditionally considered, you know, energy-efficiency portfolio funds might be migrating in a significant way over to fuel substitution, because the three-prong test is getting easier.

So, where does that kind of migration fall into the AAEE? How much of that is likely to be -- if we're really looking at the portfolio and trying to figure out what the impacts are, you know, how much of that is sort of fuel substitution and how much of that is efficiency portfolio in terms of, you know, modeling what's likely to happen going forward?

Is that a discussion we're going to have or is that something there are already some thoughts about?

MS. NEUMANN: I suppose it will be a discussion that we will have, right. I don't think we're ready to do this at this point. There's just still too much uncertainty.

COMMISSIONER MCALLISTER: I mean, that makes sense. I guess I would sort of ask all the stakeholders to weigh in on this --

MS. NEUMANN: Uh-hum.

COMMISSIONER MCALLISTER: -- because I think there's a lot of uncertainty about how much the industry is actually ready to actually do that. And as projects get proposed, as the PUC's third-party process -- you know, they're going to bid out programs to third parties, for the most, this portfolio. When those proposals come in and some of them, many of them, possibly, are for fuel substitution, that's going to really impact, potentially, the near term of what happens out there in the world that we need to capture. We need to capture it somewhere in the future load shapes, you know, in the future, different wedges that we're putting together. Whether it's the codes are on the DR side or, you know, the EE side or, you know, other parts of the forecast so -- or, other components of the forecast.

So, I think that's a complexity that, really, we're not going to be able to avoid -- well, not that we want to avoid it. But just we're going to have to engage with that, I think, pretty clearly.

I had a specific question about the load shapes. So, the hourly work, are we using the data from mainly PG&E, but perhaps other utilities that have leveraged the NMEC, the Normalized Meter Energy Consumption data to look hourly impacts of efficiency measures from the programs? There are some interesting experiences that have actually shown load shapes of savings, you know, sort of the hourly savings shapes for different end uses, for specific programs.

And PG&E was kind of the pioneer on that, but it seems to be taking hold and I think will in this portfolio going forward.

MS. NEUMANN: We're using the ADM load shapes that were developed as part of that contract.

COMMISSIONER MCALLISTER: Okay, okay, so that --

MS. NEUMANN: Yeah, but this is interesting, yeah.

COMMISSIONER MCALLISTER: Yeah, there's some really interesting work being done with the metered energy data, hourly data, sort of, you know, gathering up participants and programs to figure out the hourly profile of savings. It seems like Chris may be aware of that.

And that's likely, I think, to promulgate more throughout the programs. So, Chris, maybe you've been talking to them about that?

MR. KAVALEC: I just wanted to mention that ADM is developing load shapes, plus an hourly load model, which houses all those different load shapes.

COMMISSIONER MCALLISTER: Uh-hum.

MR. KAVALEC: And the idea is that ADM provided us load shapes based on the best information they could gather at the time. But the model is set up to introduce new load shapes as we get new information.

So, certainly, if we get better information on efficiency load shapes, then that would replace what ADM has included.

COMMISSIONER MCALLISTER: Okay, great. So, you know, the CalTRACK tool over at -- that PG&E developed, and it's getting some good traction.

MR. KAVALEC: Yeah.

COMMISSIONER MCALLISTER: I think that's got a lot of data in it that will be useful for us.

MR. KAVALEC: Yeah.

MS. NEUMANN: Yeah, the AAEE hourly load model will also accept any load shapes in it, fully calendarized as well. So, that's a possibility.

COMMISSIONER MCALLISTER: That's great. Thanks a lot, that's all the questions I have.

MS. NEUMANN: Thank you.

MR. FUGATE: Okay, our next presenter is Cary Garcia to review the CED -- no, I'm sorry -- yeah, the preliminary forecast results.

MR. GARCIA: All right. I made a last-minute adjustment to my slides, so I'm just making sure I'm looking at the right one. I was also trying to slow down for this presentation, but it looks like I might have to speed up a little bit. Eleven-forty-five is the time, right?

COMMISSIONER MCALLISTER: Yeah, we have until 11:45, so if you can bang it out without losing content, that would be great.

MR. GARCIA: Okay. I'll probably breeze through some of the earlier stuff, though. I just wanted to give a quick overview -- oh, I should introduce myself. I'm Cary Garcia, I'm attempting to be the lead forecaster for the Demand Forecasting Office.

And so, I just wanted to give an overview of our demand model system and I'll get into the statewide results that we have developed for the preliminary forecast this year.

So, I'm going to start off with the demand model systems. And so, as we kind of talked about earlier today, we have some of the modeling inputs at the top here. And so, as we mentioned, we have the economic and demographic information, so that's largely going to come from Department of Finance and Moody's Analytics.

We have our efficiency information and demand response that will go into the models, as well. As well as the electricity and natural gas consumption data we collect through our QFER, which is our Quarterly Fuels and Energy Reporting system.

And so, this year, I should also mention, we did an update. So, in the previous forecast, the Energy Update 2018, we were using 2017 history. And so, now, we've included 2018 history for electricity consumption, which is a combination of the measure -- or, estimated electricity generation from self-generation, like PV for example, as well as the actual utility sales that are reported to us.

And so, that information, those three items at the top feeds into our three buckets of models. So, one being the transportation and energy demand models. Mark will talk about the light-duty electric vehicle forecast a little bit later, that's within that.

We have our sector models that are broken out by specific sectors. So, residential, commercial, AG, industrial, mining. Let's see, TCU, which is telecommunications, utilities, as well as like street lighting in there.

And then, we have our self-generation model that does our forecast of PV capacity and generation impacts, as well as other self-generating, like combined heat and power, for example.

And as I mentioned, some of that information coming out of the self-gen model is going to feed back into that electricity and natural gas consumption data to recreate what consumption would be. Which, as I mentioned, is the aggregation of what the sales was and then what we estimate the generation from our consumption from self-generation would be.

And so, the output from those three buckets there feeds into our summary model, where we do various calibration and adjustments for weather, for example. And then, from that summary model, that's going to feed into our peak demand and hourly model that we'll talk about later today.

And then, right at the very bottom, we get to a preliminary and later this year a revised forecast.

And so, just breaking down the demand scenarios that we use. So, we have three primary demand scenarios, the high demand scenario, which generally has higher economic and demographic information. It also has climate change, that I'll talk about a little bit later, and electric vehicle forecasts. And those will be high impacts for all of those.

Counter to that, we have lower electricity rates and self-generation, as well. The idea being that with those lower rates, at least to create a nice balance in that high scenario, you would expect higher electricity usage. Then if you have those lower rates, it would also make self-generation less economic. And so, you'd have less self-generation adoption.

In the low demand case, it's the antithesis of that for the economic and demographic information, as well as electric vehicles. But as I said, now we have higher rates, which is going to do the inverse of what I mentioned before for the high demand case. So, now, you would have higher rates and, therefore, higher self-generation in the low demand case. Therefore, lowering that demand case.

And in the low demand case, we don't have climate change, either.

Now, in the mid demand case, that's essentially in between, obviously, our high and our low cases. But we also include a moderate amount of climate change in that and I'll talk about that a little bit more.

And so, this is just a quick break out of our electricity planning areas in the State. We have about eight planning areas, including Valley Electric Association that we talked about. Those bold items are highlighted because that's -- you'll probably see in the agenda those are the items that I'm going to focus on later today, when I discuss the planning area forecasts.

So, just a little bit about statewide drivers. As I mentioned, we use Moody's Analytics primarily for our economic and demographic information. But for population and household information, we use Department of Finance information for those.

Although, we do modify the household forecast to use Moody's projection of that to give us a better spread in our high case scenario.

But otherwise, you can see in the bottom there the population estimates are the same as last year. A slight change in the household projects, but you'll notice the mid and the low are the same, as I mentioned.

And then, we do have some reductions in the personal income, which is going to drive your residential forecast. Usually, we use personal income per capita. So, given the population's the same, we're going to have a lower income per capita there.

And then, also, manufacturing output which is going to affect our industrial and mining sectors. That's been reduced a little bit in comparison to last year.

But our commercial employment is about the same. Some of these numbers are rounded, so there is a small decline, but relatively close to the same as last cycle.

But the overall picture here is that

manufacturing output goes down a little bit, as I said, which affects those industrial sectors. And then, with the personal income decline relative to the previous forecast is going to bring down your residential forecast a tad bit.

Now, I'm going to get into some of the other key components that we include in the forecast. So, as we talked about -- sorry, Nick talked about earlier this morning, we did roll over program savings that otherwise was not included last year. Now, we've moved forward to 2019, and so we're going to include the new program savings that was previously a part of the AAEE analysis.

So, ultimately, this shakes out to -- it basically peaks in 2019. That's when these new programs are going to start, and then they're going to decay off. And then, you would have AA would get developed, again, and you would see some new program savings added on into the forecast. But for right now, we're not including any AA scenarios in our baseline forecasts.

But, ultimately, this is about 19,500 gigawatt hours in 2019. And as I said, that starts to decay as program savings declines. And about 4,500 gigawatts are going to come from the POUs in our forecast.

And so, we get this information primarily from the CEDARS database, from the CPUC. Since we're trying to educate a little bit more, that actual acronym is the California Energy Data and Reporting System.

And then, we get the POU information from SB 1037 reports for the POUS.

And in addition to the committed savings from programs, we also included new codes and standards savings, so that will be the Title 24 savings for residential buildings and commercial sector.

We also included some more federal appliance standards, as well. And so, that will be added into this baseline forecast. And that will cause a difference compared to last year. We have these new standards that will come in, so that's going to increase that savings relative to the last cycle.

Here's the climate change scenarios that I was mentioning. So, as I mentioned, we don't have a low scenario for that. So, the low scenario will assume no climate change impacts. But we do include a high scenario of climate change in the respective high scenario and, likewise, in the mid scenario.

And so, these impacts are primarily going to happen in your heating and cooling sectors, where they're the most temperature responsive. So, obviously, residential and commercial sectors are going to get adjusted by this.

And so, what we do is we develop an econometric model that basically teases out what that temperature response is going to be. Scripps Institute of Oceanography develops these scenarios for us. Essentially, a higher change in temperature and then a moderate change in temperature. And so, given that we have a temperature response, we simply apply the trend for that high scenario to get us what that -- to determine what that impact would be in terms of gigawatt hours or therms, for example, in a gas consumption gas.

I'll pause here real quickly, if there are any questions along the way from your guys. All right. this stuff is pretty routine here. We're getting to the more interesting stuff.

So, I don't want to take some of Mark's thunder right now, but this is just a brief overview of the light duty electric vehicle consumption. So, 15,000 gigawatt hours by 2030. You can see the red line up there is our previous forecast and our blue line is the new mid case from the preliminary forecast.

You'll definitely see the distinction there. It's slightly lower. And that's going to be the result of an allocation of more residential electric vehicles versus commercial. And then, when you do that, it's basically residential vehicles are going to have a lower

VMT relative to commercial. And so, that will drive down your electricity consumption impacts from the overall light duty vehicle forecast.

And I should also note that the growth rates are mainly the same. I think it's growing, right here in my notes, roughly 13 percent on average from 2019 to 2030. So, in comparison to like the residential or commercial sector overall, it's a tremendous amount of growth in those, in vehicles. And this is roughly three and a half million vehicles statewide.

PV energy Impacts. Once again, I'll be brief because Sudhakar is going to go over this today, this afternoon. But the one thing to note is that you'll see the distinction between our -- the red line there, once again, the mid case from last year and the new mid case. Roughly, a 5,000 gigawatt hour difference in 2030.

And one reason is that the overall PV forecast, in terms of capacity went up a little bit. But there's also, if you remember our last baseline, we included -- in our last forecast, we have our baseline forecast and then we included AAPV for the Title 24. And so, now, that's been wrapped up into our baseline forecast, and so that's going to bump things up a little bit when you look at this type of comparison.

This is an overview of the baseline consumption forecast on a statewide basis. It's just comparing our mid cases, over there on the left side, the preliminary on the top and then the update on the bottom there. And you can see, as I mentioned, the residential consumption forecast. Once again, this is the combination of self-generation and sales as to what your total consumption would be for that sector. It's dropped down a little bit, as I said, from that reduction in personal income growth and relatively slow housing growth.

The commercial sector is growing a little bit and that's primarily from the continued growth in commercial floor space.

And industrial and mining, as I mentioned, the manufacturing output information that we received from Moody's showed a decline there. And you can see that reflected here in these growth rates.

Agricultural is about the same. And then, TCU has a slight reduction.

Looking at our baseline consumption in this graph --

COMMISSIONER MCALLISTER: Hey, Cary, can I jump in real quick? I'm going to have to go. I actually have to walk over to the Capitol. But how far in are you?

MR. GARCIA: I can probably --

COMMISSIONER MCALLISTER: There's a bit more.
MR. GARCIA: If you come back, I can probably wrap it up pretty quickly and we can move on.
COMMISSIONER MCALLISTER: Yeah, I've got to walk over. I can't keep the Legislature waiting, mostly. But I think probably the best thing to do is to give a little hiatus and come back at 1:15, if that's okay with everybody. I do want to catch this.
MR. GARCIA: Okay.
COMMISSIONER MCALLISTER: So, okay. So, let's see, so, Nick, is there anything else to say? Anything else to say to folks, where the good restaurants are or whatever?
MR. FUGATE: Yeah, sure. So, anyone looking for food who's in the building, you know, we have a new market. If you just walk a couple blocks up to 9th Street -- I get turned around which direction it is. Up 9th Street. And then, you now, there is also a food truck, I think right outside. If you walk out the front of the building and take a left.
So, we will reconvene at 1:15. Thank you, everyone.
(Off the record at 11:47 a.m.)
(On the record at 1:18 p.m.)
COMMISSIONER MCALLISTER: All right. Well,

thanks for sticking around. There's a little bit sparser audience than there was this morning. I guess, maybe, lunch was really good and they're lingering.

MR. FUGATE: Or they melted.

COMMISSIONER MCALLISTER: Yeah, or they went outside and melted, yeah. But thanks for adjusting the schedule. I appreciate that for giving us a little more time between the morning and the afternoon.

And, so, anyway, I had to brutally cut off Cary, so we'll get started where we left off.

MR. GARCIA: That's fine. I backed up just a little bit to get to the consumption part. This is really where we get into like the actual numbers.

So, just to reiterate, really quickly again, you may remember this chart. So, we have this decline in the residential sector consumption. Commercial sector grows a little bit there. And you'll see that, as I mentioned earlier, the industrial and mining sectors declining due to the reduction in -- I think they're adjusting my volume. Okay, it was too loud.

And then, agricultural, once again, remains about the same, as well as TCU, although a slight decline overall across the State.

And so, looking at these graphs here, so I'm comparing the history against our previous forecast.

That's the red line and CEDU, the California Energy Demand Update 2018 mid case, against our new high, mid and low cases for this preliminary forecast.

So, as I note here, it's about five percent lower. Obviously, we have a lower, 2018 actual, as I mentioned before. We were using the 2018 value from the 2018 forecast, was that forecasted value using 2017 consumption data.

COMMISSIONER MCALLISTER: Hey, Cary, this is not weather normalized, right?

MR. GARCIA: We do a slight weather normalization, actually.

COMMISSIONER MCALLISTER: Huh.

MR. GARCIA: So, you'll see a little tick down, like a little hockey stick at the very end there, in 2019.

COMMISSIONER MCALLISTER: Yeah.

MR. GARCIA: And that's going to be the adjustment. We basically start from average weather in the forecast, but we make an adjustment using actual weather compared to the 30-year average. So, that's what brings that down a little further there.

COMMISSIONER MCALLISTER: Oh, okay.

MR. GARCIA: So, the 2018 it's starting from is the actual, actual and then it drops down a little bit more in the 2018 period.

COMMISSIONER MCALLISTER: Okay. Okay.

MR. GARCIA: You can quote me on the "actual, actual."

COOMISSIONER MCALLISTER: The actual, actual, yeah. So, but that's a -- I mean, what is that, about 40,000 gigawatt hours difference just right off the bat?

MR. GARCIA: Yeah, right off the bat there. Ultimately, the growth rates are about the same. So, in the -- let's see here, I'm looking at my numbers. So, yeah, it's a 3 percent reduction just in that 2018 value. That 5 percent lower is actually a little bit later in the forecast. But the growth rates are 1.2 versus 1.3 percent, ultimately, comparing the two mid cases. And the high case is about one and a half percent. As I mentioned, we had a higher household forecast for the high case. You see that go much higher than the other two cases. And the low case is going at just under 1 percent.

COMMISSIONER MCALLISTER: Okay. You have this for capacity, as well? This is energy sales?

MR. GARCIA: No, this is actually total energy consumption. So, this is going to include --

COMMISSIONER MCALLISTER: For energy consumption, yeah.

MR. GARCIA: Yeah, it includes the sales --

COMMISSIONER MCALLISTER: Oh, right, I gotcha.

MR. GARCIA: -- for self-generation.

COMMISSIONER MCALLISTER: Yeah, I gotcha, I gotcha, okay.

MR. GARCIA: Right. I have a slide later on where I get into the sales forecast.

COMMISSIONER MCALLISTER: Okay, got it.

MR. GARCIA: And this is our usual graph of consumption per capita. So, essentially, just taking that consumption and dividing it by the population projections that we have. And as we saw in the previous graph, we have a lower baseline consumption. So, that's going to reduce our per capita estimates.

But similar growth rate, similar to the consumption I showed before, just a minor difference in growth rate, so .4 percent versus .5 percent in the last forecast. And that adjustment that you saw, dropping it down to the new, historical starting point is evidence here as well.

This next slide breaks down that consumption forecast into the sectors that we use in our models. And so, at the top there you can see the residential and commercial sectors are the bulk of electricity consumption in the State.

And then, light-duty electric vehicle consumption is going to be added into those two sectors as well, and so that's going to have them also grow a little bit faster than the respective sectors.

And you can see at the bottom, we have the industrial, AG, TCU, and the mining sectors, as well as street lighting. It's a very small sliver. I think it's like a fraction of a percent of statewide total when you look at the numbers there. But you can see those are pretty flat in terms of consumption. As I mentioned, industrial and those sectors have been pretty flat for well over a decade, and so we see that continuing into the future with a little bit, a slight decline at the end there.

If you're actually -- like, in percentage terms, the industrial sector is around 12 and a half percent of the statewide total consumption and AG is around 6 and a half percent relative to those commercial sectors, commercial and residential combination of about 70 percent.

And that remains pretty constant from the starting points. It grows a little bit but you can obviously that that Dutch share kind of takes the bulk of it.

This is the sales forecast. So, in this case, it's the consumption minus the self-generation that we're forecasting, so it gives us the total electricity sales that the customers are ultimately buying in their sectors.

So, once again, a lower 2018 actual in compared to the last forecast. And here, we can see the increase in the behind-the-meter PV capacity that's going to cause that reduction, a slight slow down in growth. Ultimately, it's around .6 percent for that mid case, in blue, compared to the red line that is our old forecast is around .9 percent growth. And that's going from 2019 on average per year to 2030.

And you see that the low case there is pretty slow. And then, also keep in mind there's a little bit of climate change. But it's going to be -- we're using similar projections as last year, so that won't cause any differences. But that's also incorporated in our high and our low cases, as I mentioned earlier this morning.

Just for reference, too, the high case is about 1.2 percent compared to the .6 that we have now. And the low case, obviously, is about zero, as you can see from the graph here.

And I'm just reiterating, again, you really see that slow down in the industrial and mining sector, causing that reduction in growth, as well as a little slightly slower growth in the residential sector.

And it's similar to the consumption break out that I showed. And so, now, you can really see the impact of that PV generation there, flattening those residential and commercial sector forecasts out. And as I said, there's a little faster growth in commercial sector PV, which is going to slow down those commercial sales relative to the residential sector forecast.

And then, here is the statewide coincident peaks. So, this includes both the IOUs, as well as the other planning areas that I mentioned this morning. So, ultimately, if we're having a -- going to have a slower sales growth, then you'll have a slower growth in peak demand. And then, also, there's going to be a peak shift included that bumps things up a little bit. And so, we only incorporate that for the IOUs, which we model on an hourly basis, that Chris will talk about later today. But, ultimately, that shakes out to about 4,200 megawatts of additional peak demand, relative to the previous way we forecasted, which did not account for the impacts of DER. So, PV and light-duty vehicles on an hourly basis.

Then here, this is a last-minute addition. We had to make a few tweaks to our natural gas consumption forecast. And so, this is actually end-use natural gas consumption forecast. So, once again, similar, the same models that we're using for the electricity side and, basically, the same drivers, but slightly different because you're looking at, obviously, natural gas usage as the end uses versus the electricity end uses.

And so, here, we can see that adjustment from the QFER 2016. So, slightly different than the previous comparison. We didn't do a natural gas update, as we do for electricity. So, this is comparing against the CED 2017 forecast.

The few notes that I have here. So, we're not -- we mentioned before and Nick mentioned this, we're not incorporating any fuel or significant building electrification this round, but we'll look at that for the 2021. There's going to be sort of -- it's inherent in the name, there's a substitution going on. So, if there's an increase in electrification for like heating, and water heating, and space heating, there would be a decline on the end-use natural gas side that would be comparable.

So, we're including a small amount of natural gas vehicles in here, as well. So, by 2030, that's ultimately about 150 million therms of natural gas vehicles, which is a slight increase in comparison to the last forecast.

You also see that big jump up in consumption, from 2018 to 2019, and that's also weather adjustment in the residential and commercial sectors. So, basically, the 2018 historical HDV is a little bit lower than the historical 30-year average. As I mentioned before on the electricity, that jump over there.

And this is especially true for SoCal Gas and San Diego Gas and Electric. So, it's affecting the Southern California portion of the State.

Ultimately, growth in all three scenarios has dropped compared to 2017, and that's most because of the 2019 Title 24 standards, as well as a reduction in growth in the mining sector. So, similar things playing out in terms of gas, as with electricity that I mentioned before.

The 2019 mid case also falls relative to the 2019 mid case. You can see how -- or, the low case. You can see how they kind of both match other by 2030. And that's going to be due to climate change. So, we don't have any climate change in the low scenario. But as I mentioned, we do include it in the high and the mid. But what's happening over here is that it's going to be affecting climate change in terms of heating degree days. It's actually going to bring your heating degree days a little bit, so you're no longer be using space heating. You won't have as much space heating based around natural gas, so that's going to bring that down to match the low case there.

And that's all I have for this. I'll just leave as questions or comments there.

COMMISSIONER MCALLISTER: No, it's pretty clear. I guess the one question I have, just about the natural gas, is that there's not a whole lot of difference between the mid and the low. And is that just because the climate change impacts aren't -- I guess, what else could affect the difference between -- what else changed between low and mid, or is it pretty much just the climate change impacts that got put in?

MR. GARCIA: It's primarily going to be the climate change impacts.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: Yeah, so -- I always get the CDD and HDD, I have to remember it's like one side of the equation where --

COMMISSIONER MCALLISTER: Right, right, right, right.

MR. GARCIA: So, in the heating degree days, if it's a little warmer, you're going to have less heating degree days.

COMMISSIONER MCALLISTER: Yeah.

MR. GARCIA: But you're going to have more cooling degree days. So, on the electricity side it's going to bump things up, whereas on the natural gas side it's going to bring things down a little bit.

COMMISSIONER MCALLISTER: Oh, it's the same conditions on the scenario.

MR. GARCIA: Exactly.

COMMISSIONER MCALLISTER: Yeah, okay, gotcha. That makes sense.

MR. GARCIA: But it's almost -- I guess it's probably almost similar to the fuel substitution kind of idea, right.

COMMISSIONER MCALLISTER: Yeah.

MR. GARCIA: Like if you're making a reduction on one side, replacement is going to happen. But it just so happens --

COMMISSIONER MCALLISTER: Yeah.

MR. GARCIA: -- it occurs with the climate scenarios.

COMMISSIONER MCALLISTER: Yeah, got it. Thanks.

MR. GARCIA: I have no idea who's up next. I didn't look at the agenda. Nick, please help.

MR. FUGATE: I keep forgetting we don't have Heather here today. So, next we have, our next speaker is Mark Palmere, and he's going to present on our electric vehicle forecast.

MR. PALMERE: Good afternoon Commissioners, and stakeholders, and members of the public. I guess just one Commissioner, I guess.

My name is Mark Palmere and I am with the Transportation Energy Forecasting Unit. And I'd just like to present a brief overview of our transportation electricity demand forecast. And that includes both light duty vehicles, as well as medium, heavy duty freight, and public transportation. So, this is the overall transportation electricity demand.

To start with, I'd like to look at some historical slides. This shows PEV sales over the past decade or so. And as you can see, they've been rising quite dramatically, starting with, you know, only a few thousand in 2011 and 2012. And by 2018, they eclipsed 150,000 sales annual for the first time ever.

Through March of this year, which is the latest where we have what we consider reliable data, there have been approximately 560,000 light duty PEVs sold in the State of California.

And another way of looking at the sales numbers is by looking at the PEV sales for the share of overall light duty sales. Again, you can see 2010, 2011 very low numbers, but by 2018 it got to has high as 8 percent of overall sales for either BEVs, battery electric vehicles, or PHEVs, plug-in hybrid electric vehicles.

And, you know, based on the numbers we've seen so far, we do expect that trend to continue. And that's sort of what I'm going to talk about a lot is our forecast future trends.

And then, I would also like to talk about the difference between the two types of PEVs. So, we hear a lot about PEV sales and goals as the number of PEV sales. But PEVs aren't all created equal, especially when it comes to electricity use. Where BEVs use 100 percent electricity, PHEVs do not because they can also run on gasoline. So, it's important to distinguish between the two in our forecast, which we do.

And, historically, PHEVs were more popular than BEVs. Back in 2012 and those early years, for example the Chevrolet Volt was one of the best selling PEVs on the market and it's a PHEV. So, that's why you would see more PHEVs. But for a number of reasons, Tesla not the least which, BEVs have been gradually gaining share among PEVs. And it surpassed 50 percent for good, so far in 2015, and by 2018 it was over 60 percent of PEVs sold were BEVs. And we do expect that trend to continue for a number of reasons. But based on our attribute forecast, which I will go into, in more details, the conditions seem to be more favorable for BEVs. And coupled with historical data, we do expect to see more BEVs than PHEVs.

As I mentioned, vehicle attributes, this is sort of what we use to determine our forecast numbers. We use a number of attributes, both from the vehicle side, from the consumer side, and from the general econ demographic side. These are just the vehicle attributes which do account for regulatory requirements.

And for light duty vehicles, the attributes include range, price, fuel economy, acceleration, number of models available, refueling time, maintenance cost, cargo capacity. And we do weight them by importance based on our California vehicle sales. So, these are not all considered equally in our forecast.

Because in our vehicle survey we ask the respondents to sort of choose vehicles based on hypothetical attributes, and we use that to model how important people find each specific attribute.

Unsurprisingly, price is consistently considered the most important attribute. Range and fuel economy are also very important. So, you know, the other ones on that list, you know, cargo capacity, acceleration, it's not that we think they're unimportant, it's just that they aren't weighted as much. But they are definitely considered and we do model those attributes as well, going through 2030.

And all this leads us to our forecast, which is shown here. This is by all fuel types. Obviously, this workshop is about electricity demand, so we're going to focus on the red and the purple lines, and that indicates BEVs and PHEVs, respectively.

The graph starts at 20 million. Everything below that is all gasoline. But you can see, as we move forward, the gasoline numbers aren't really increasing and that's partially because BEVs and PHEVs, to a lesser extent, are forecast to increase by a quite large amount.

And this is the --

COMMISSIONER MCALLISTER: Hey, Mark, can I jump in and ask a question about that?

MR. PALMERE: Uh-huh.

COMMISSIONER MCALLISTER: So, this takes into account all the fuel economy increases and everything, so these are absolute numbers of gas consumption, right?

MR. PALMERE: Oh, sorry, I should have clarified. This is vehicle --

COMMISSIONER MCALLISTER: Proposed vehicle population. I'm sorry. I'm glancing at it and trying to multi-task and I didn't --

MR. PALMERE: Yeah. No, I should have clarified that.

COMMISSIONER MCALLISTER: Okay.

MR. PALMERE: But, yeah, we will do --

COMMISSIONER MCALLISTER: Okay, so this is population of cars. Okay, I got you.

MR. PALMERE: This is the number of vehicles on the road.

COMMISSIONER MCALLISTER: I got you.

MR. PALMERE: Yeah, so we have gasoline --

COMMISSIONER MCALLISTER: Yeah, thanks. Sorry about that.

MR. PALMERE: Oh, yeah, no problem.

And then, as I mentioned, the attributes, I had that slide about vehicle attributes. This slide sort of characterizes -- it may be a bit hard to read. It may be easier on your handout. But I'll just go over it, briefly.

So, we've got vehicle attributes, so we've also got incentives and preferences. So, the preferences, not only do they weight the importance of the attributes, but they also measure consumers' preferences for PEVs in general, versus other fuel types.

Whereas, there's like an inherent value of a vehicle being a certain fuel type. And based on our surveys, we do find that consumers, all else being equal, do prefer BEVs and PHEVs to gasoline vehicles. And not only is that the case, but based on our modeling we increased that preference through the forecast in every case, but our low case, due to the fact that as the vehicles become more prominent on the road, people will become more aware of them. And, as a result, likely more interested in them.

COMMISSIONER MCALLISTER: Uh-hum.

MR. PALMERE: Incentives, that's another really important one. We have the federal and state credit and rebate, respectively, as well as carpooling access. And we do have those being phased out in the middle of the next decade, based on our assumptions of, you know, how much it would cost and what it would do to the funding. We kind of expect in our mid case the rebate to be phased out at around 2025. But in the more optimistic cases, we have it continuing through the forecast.

The same with HOV lane access. The federal tax credit, that one's a little more consistent throughout our different scenarios because they do have a set language in place about where it is phased out for manufacturers that reach over 200,000 sales. And so, we are decreasing the effect of it based on when we expect manufacturers to have reached that. Tesla and GM already have, so it's already being taken into account.

Then, the attributes, as I mentioned, so the price is the most important one in our model. And these are based on -- our overall vehicle prices are based heavily on battery prices because that is one of the main components, and one of the barriers to lower costs of EVs. Batteries are still quite expensive.

But based on our modeling we have, you know, in the reference case it's down to $100 per kilowatt hour. But in our high case, it's down to $80 per kilowatt hour. And in our aggressive case, which isn't officially a part of the IEPR, but just a modeling exercise, it's also -- it's down to as low as $70 per kilowatt hour.

We've gotten some questions about price parity. That's kind of a trending topic. People want to know when is it going to be equal to EVs -- or, equal to gasoline vehicles. And the answer is not as simple as a number because what we do, is we measure it by different classes of vehicles. So, there's going to be some classes we forecast where it will get very close to gasoline price parity, but not as much in others.

And that's just a factor of what, like what makes are available, whether it's like a more upscale class availability, then it's less likely to reach parity. So, there's no like set answer to that. But in our forecast, the prices are definitely a lot more competitive and they -- even in the reference case, they get very close to gasoline, even if they don't quite reach them.

And then, range right now, it's over 300 miles by 2030 in all of our cases. Refueling time is lower and so is the time to stations, which measures how far people have to go in minutes to get to the nearest station.

COMMISSIONER MCALLISTER: Uh-hum.

MR. PALMERE: And all that gives us the numbers by PEVs. So, we saw the overall distribution, but this is just PEV-specific. So, in our reference case we have about 3.6 million PEVs on the road in 2030. In the high case, it jumps up to 4.6 million. And in the aggressive and bookend case it's over 5 million.

And these are all, you know, very positive numbers compared to where we are right now. As we can see, the black line is historical and the colored lines are forecast numbers. And even in the low case, we have over a five-fold increase. So, based on our forecast, things are definitely very optimistic for PEVs. And that's due to a number of factors that I went over, the lowering of prices, increased preferences, increased availability, and the rebates.

And, as I mentioned, BEVs versus PHEVs, we saw the historical graph of BEVs are becoming more popular than PHEVs. Here, this is our forecast which kind of continues that trend. By 2027 we have -- we are forecasting over twice as many BEVs on the road, than PHEVs, and that number will only increase based on our forecast. And again, that's very important for electricity consumption.

And then, I want to talk a little bit about medium and heavy duty numbers. The battery electric truck stock, in the mid and high case, is forecast to be much higher than it is now. As much as 25,000 medium and heavy duty trucks on the road in 2030 and about 10,000 in the mid case. The low case, that's less favorable for battery electric technology. It's expected to not really get off the ground. But in the other two cases it is very optimistic for that, as well.

The same with the school bus population. This is the mid case, I believe, and it's based on historical numbers and the announcements. For example, the announcement that the funding, the CEC-approved funding for over 200 electric school buses. You can see that in the chart that it's definitely expected to go up, as well. And by 2030, our numbers have over 2,000 electric school buses on the road, which is a really good amount of progress.

And then, electric transit buses. And this is modeled a little different than freight because so much of what transit buses funding comes from, the government -- the government funding, so it's easier to expect them to use electric buses. So, that's why we see in all cases electric buses are making a dent in the overall number of buses, up to 3,000 to 5,000, depending on the case. Which statewide, that's a very significant number.

And all that leads up to our overall electricity demand forecast. This morning, Cary showed the light duty vehicle electricity demand forecast. And if you have that chart out, you'll see that it looks very similar because overall we expect a great majority of the transportation electricity demand to be light duty vehicles.

But as you saw in those recent charts, those freight, buses, and school buses also expected to increase their electricity demand.

And all of that leads to about 16,000 gigawatt hours demand in 2030 in the mid case, but as high as 20,000 in the high case. And so, that's a very significant amount of electricity. Obviously, we model it at the annual level, so we don't focus as much on load shapes, but it's something that is becoming more and more relevant to the overall electricity demand forecast. And we definitely are continuing to model it and continuing to see positive trends for transportation electrification.

And that is my last slide. I want to just talk briefly about our team. I'm one of many, including our new supervisor, Heidi, Anis Bahreinian, who is our lead forecast and would be presenting this, but she is out of the country, actually. Bob McBride is right there and he is the one, our expect on freight modeling. Jesse Gage does our DMV analysis. Elena Giyenko does ZEV incentives, as well as the bus modeling. Ysbrand van der Werf does fuel prices and urban modeling. And Sudhakar Konala, who's presenting next on solar attributes, does double duty, because he also does a lot of ZEV attributes for us as well. And all of the contact information is there, so if you have any further questions about any specific topics, please feel free to reach out to us. And we're also open for public comment after the workshop.

COMMISSIONER MCALLISTER: Yeah, right.

MR. PALMERE: Thank you.

COMMISSIONER MCALLISTER: Thanks, Mark. It's really, actually really phenomenal, the development of these markets. I mean, you know, just from year to year, the last, you know, six years, the last four forecasts, or whatever, it's a whole different ball game, now, in terms of the scale we're getting with EVs.

MR. PALMERE: Yeah, it's definitely changing very rapidly. And even how we forecast it, based on new developments and new technology, it changes every year.

COMMISSIONER MCALLISTER: Yeah, it's great.

MR. PALMERE: Thank you.

COMMISSIONER MCALLISTER: Thank you.

MR. FUGATE: So, our next presenter is Sudhakar Konala, to talk about our self-generation forecast.

MR. KONALA: Good afternoon Commissioners, stakeholders, members of the public. Today I'm going to be -- I'm Sudhakar Konala, and I will be presenting the self-generation forecast, but mainly I'm going to be concentrating on the PV forecast.

So, just a brief overview of what I'm going to be going over. So, I will briefly go over the forecast methodology for the forecast. And then, I'm going to review some historical self-generation information in terms of capacity and energy.

Then, I'm going to go through our statewide forecast before diving into individual forecasts for the utility/planning areas. And, finally, I'll end up by giving a brief overview of what to look forward to.

So, just to start off, I want to emphasize the definition of our scenarios. So, as Cary mentioned, we have three different demand cases, the high, the low and the mid. What I really want to emphasize here is something that's kind of counterintuitive, but it's really important to understand. And that's that in the high electricity demand case, we're modeling low PV adoption. That's how we get high electricity demand. And in the low electricity demand case, we're modeling high PV adoption.

So, some of the assumptions related to PV adoption are going to be reversed compared to the demand cases.

So, here's a very high level overview of the models that we use to forecast PV growth. We have several different inputs that go into the models. They include just historical statewide, installed behind-the-meter PV capacity. But we also consider economic and demographic data, specifically growth in households, growth in commercial floor space, and residential and commercial accounts. Also incorporated into the forecast are electricity and natural gas prices. And, finally, there were some PV-specific data that are considered, such as system costs and performance.

And all of that information is fed into our models. We have two primary models, which is the residential sector predictive model and the commercial sector predictive model. And then, for everything that's not residential or commercial, we use a trend analysis based on historical installations.

Out of these three models, we get an output of statewide installed behind-the-meter PV capacity. And then, we use capacity factors that are specified by 20 different forecast zones. And from that, we get a forecast of energy generation for behind-the-meter PV.

I just want to emphasize that the residential and the commercial sectors predict PV penetration based on calculated payback period and bill savings, using a bath diffusion approach.

Okay. I also want to take a little time recapping AAPV, our additional achievable PV. In the past, AAPV accounted for, at what the time was proposed standards, for PV requirements for new homes.

Our baseline forecast forecasts adoption of PV for new homes. But AAPV was defined as the difference between PV adoptions for new homes due to the 2019 Title 24 regulations compared to what the market forecast was.

And that difference between the market forecast and the regulations is the definition of AAPV.

So, in 2019, since the building standards officially became law, we have incorporated AAPV into the baseline PV forecast. So, based on this information, our forecast of PV adoption for new homes is now based entirely on regulatory compliance, rather than a market forecast.

In terms of the assumptions of regulatory compliance, they remain the same from previous forecasts. So, in the low energy demand case, we're assuming 90 percent adoption for new homes. In the high case, it's about 70 percent, with the mid case coming in at 80 percent.

Also, assumptions of the average PV system size for new homes remains the same from previous forecasts.

I do want to make one point. In terms of the PV forecast, I am going to be restating some of the results from previous forecasts. The reason why I'm doing this is because previous forecasts don't necessarily include AAPV in the baseline. And if I were to present those results, there would be a huge difference without having a meaningful insight. So, it's my way of doing an apples-to-apples comparison.

So, just a brief overview of the specific inputs that were updated for the 2019 preliminary PV forecast. We have a whole new dataset of PV interconnection data. And most important of all from this is new data coming from the 1304-B regulations. It's a new dataset that's been available to us for this year, for the first time.

Also updated, economic and demographic data that Cary Garcia went over. We also updated electricity rates and electricity rate schedules, when appropriate. And then, we updated historical PV system costs as well.

I briefly want to do an overview of the interconnection data that we use to generate the historical PV installation data. So, in gray are data sources that we've used in the past. They still remain part of the historical dataset, just because to update the entire historical dataset is a large undertaking that is reserved, probably, for an off-IEPR year.

But what I want to emphasize is that from the last forecast to this forecast we do have several new datasets, especially the 1304-B dataset. So, we relied on that heavily to update installations through 2018.

Okay. So, now to some historical PV installation data. So, at the end of 2018, there was about 8,100 megawatts of total installed capacity. And what we're seeing is that over the last three years the PV market has been maturing, with installations averaging between 1,300 and 1,400 megawatts annually. And, specifically, we are seeing more growth in the commercial market, with the residential market being relatively flat over the last four years.

In addition to that, there was about 150 megawatts of energy storage that's been installed at the end of 2018, 52 percent of which was in Southern California Edison's territory. And of the 150 megawatts, about 90 megawatts of storage was installed in the last two years alone. So, we do an acceleration in storage going on, as well.

So, here I just have a list of installed capacity broken down by some of the larger utilities, and I guess the mid and major utilities as well. It's just for reference, for anyone that's interested. I'm not going to spend too much time going through it.

The main points I want to make is that the large, the big five utilities, the IOUs, LADWP and SMUD, they account for over 95 percent of the total installed capacity in the State. And if you consider some of the smaller ones, we're actually over 99 percent. So, that is the updated dataset that we're working with for the historical installed PV capacity.

So, with that, I'm going to get into the forecast. First, I'll start with the statewide forecast. So, here's a chart of self-generation, both historical and forecasted for the State of California. In 2018, there's an estimated 28,000 gigawatt hours of self-generation in the State, roughly split 50/50 between PV and other.

As for the forecast itself, we assume that non-PV self-gen, which is mostly combined heat and power, is going to be relatively flat in the forecast period, and this just reflects the trend in recent years. Over the last four or five years, we don't see much growth.

But in terms of PV, we see it growing from about 13,800 gigawatt hours in 2018 to over 40,000 gigawatt hours in the mid case. So, this represents almost a three-fold growth in generation from PV by 2030.

Okay. So, if you guys have any questions at any time, please feel free to stop me, otherwise I'm going to keep going.

So, in terms of the PV forecast, as I mentioned before in 2018 there was about 8,100 megawatts installed. In the high electricity demand case, we expect that to increase to about 19,400 megawatts. In the mid case, to about 23,100 megawatts. And in the low electricity demand case to about 26,800 megawatts.

And how this compares to the previous forecasts, I have here as well. So, what we're seeing is we're seeing a narrowing of the range compared to previous forecasts. So, the low is slightly lower than the previous lows, and the high is significantly higher than the previous highs, and the mid is essentially an average of the low and high. It's slightly higher than previous mids.

The most important point to make about this, specifically, is that the high is higher mainly due to faster commercial growth, but also because actual 2018 installed PV capacity is much higher than we'd previously projected, so that is affecting the projections going forward.

COMMISSIONER MCALLISTER: So, Sudhakar, you mentioned at the outset that the driver was primarily sort of -- really, the consumer benefit, you know, the rate and the cost, and sort of the, essentially, cash flow model, I guess, or rate of return model.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: Are we sure about that? I mean, because there seems to be some kind of market dynamic that people kind of get solar. You know, there is some uncertainty around that metering. And so, like I wonder how confident people are in that calculus, but maybe decided to do it anyway. So, and maybe that could explain some of this market strength.

MR. KONALA: Yeah. Yeah, I mean, in terms of the financial auditing, it does make, you know, a lot of sense to go to solar. So, and we are doing a financial analysis, more than -- so, on the transportation side, they do surveys and they do, I guess, preferences, and we don't have that aspect in PV.

COMMISSIONER MCALLISTER: Oh, right, okay. All right, got it, thanks.

MR. KONALA: Okay. So, I'm not going to spend too much time on the next two slides, but I just wanted to give some numbers out to stakeholders and members of the public, so they could maybe review it and, if they wanted to, come back with questions later on.

So, here, I just have projections of capacity by each of the planning areas in 2030, and the differences from the 2017 and 2018 forecasts.

So, in the mid case, again, the capacity projection for statewide is about 23,000. That's about a thousand megawatts higher than the 2018 IEPR forecast an about 2,000 higher than the 2017 forecast.

I have similar numbers for energy, as well, so if you have questions, just let me know.

Finally, for this section, I have a slide on the contribution of the Title 24 standards. As I had stated previously, we incorporated the contribution from these standards into the baseline forecast, formerly known as AAPV. The standards take into effect starting next year. And, again, this is a forecast of regulatory compliance. But there is a direct correlation with these numbers and our forecast of new home construction. So, if our forecast of new home construction changes, then it's directly going to affect the contribution of the standards to the PV forecast.

COMMISSIONER MCALLISTER: Those LADWP numbers seem super small.

MR. KONALA: Yes. I was going to cover that and the LADWP people are probably --

COMMISSIONER MCALLISTER: Okay. You know, go ahead. That's fine, you can do it when you wanted to do it, that's fine.

MR. KONALA: Okay.

COMMISSIONER MCALLISTER: I mean, SMUD, I mean, their territory is so much larger, they're number of customers is larger than SMUD.

MR. KONALA: Actually, I'll cover it now, since we're on it. So, overall, LADWP numbers are not that small. This is just only the contribution from new homes. And this is directly related to the forecast of new homes in LADWP. So, what we saw is the forecast for new home growth for this year, for some reason the growth is significantly slower. And that is something we want to look into, to see why that happened.

But in the previous forecasts we have much higher growth in LADWP and this year the growth was very flat. So, that is leading to like very little growth in the AAPV portion of the residential section -- or sector.

COMMISSIONER MCALLISTER: Okay. But SMUD is so radically different that it's tenfold?

MR. KONALA: So, it's the growth rate for housing. I don't know the numbers off the top of my head. LADWP was very small and SMUD wasn't very significantly different from the previous forecast.

COMMISSIONER MCALLISTER: Okay. Okay, that will be interesting to look into, yeah.

MR. GARCIA: Yeah, I think he noticed pretty late --

COMMISSIONER MCALLISTER: Oh, okay.

MR. GARCIA: (Inaudible).

COMMISSIONER MCALLISTER: Yeah, okay, that sounds good.

MR. GARCIA: Oh, yeah. Yeah, it's not just the -- it's the calculation of additions, as well.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: So, like the SMUD growth rate is about 1 percent and the growth rate of the overall stock is a little -- I think I talk about it in my presentation later. I think it's a little below 1 percent, as well.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: But then, when you start getting into the additions and looking at what was added, we're getting some peculiar numbers on that one. And I think it's also due to how we're taking L.A. County, and we have to share it out into our forecasting zones.

COMMISSIONER MCALLISTER: Uh-hum.

MR. GARCIA: So, we have LADWP split into two zones. And that is kind of troublesome with those little pockets, and how LADWP is split, so that causes some issues. And we even compared that, our numbers against what LADWP submitted in their demand forecast for the IEPR, and there were significant differences in the housing growth. So, as you said, we're going to look into that.

COMMISSIONER MCALLISTER: Okay. Yeah, that seems like kind of an outlier.

MR. KONALA: Yeah, it makes our overall demand forecast difficult to compare as well.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: I guess the main point I'd like to make is in terms of the Title 24 standards, the growth in new home construction completely determines the disproportion of the forecast. So, any anomalies can be traced back to the household forecast, essentially.

Overall, though, for the entire State, and these numbers are for 2030, I didn't mention that, the AAPV portion is pretty similar to the previous forecast.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: So, I'm actually going to move on to some of the utility forecasts. And I have a lot more data on here than I can go through. But just for completeness, I have lots of tables in here.

So, for PG&E, I've provided the baseline forecast. In terms of total energy in 2018, theirs is about 6,400 gigawatt hours' worth of energy generated from behind-the-meter PV. In the mid case, we expect that to go up by about three times, to about 18, 2000.

Solar installations are growing at a pretty good rate, although we see faster growth in the commercial sector than the residential sector. As you can see, growth is higher in the early part of the forecast, than the later part of the forecast. That's mainly due to two reasons. One, we have the expiration of the tax credit in 2021, so that's driving some of the adoption early on and it's tapering off later on.

But also, in 2020 we have those additions from the Title 24 standards, so that's also bumping up adoptions in 2020, as well.

In terms of overall numbers, for the low demand case we see generation reaching up to 21,000 gigawatt hours and in the high demand case as low as 15,000 gigawatt hours.

And I have a chart here just showing the trends in the different sectors. So, you can see that growth is primarily driven by the residential sector in the early years, but then it's flattening out a little bit, and the commercial sector is what's growing in the later part of the forecast.

So, PG&E represents the largest portion of installed capacity in the State, so their numbers are going to kind of match the statewide average. The other utilities, I will be comparing to like PG&E as a proxy for statewide average.

So, moving on to Southern California Edison. So, for Southern California Edison, in 2018 we estimate that PV generation was about 4,400 gigawatt hours. By 2030, we expect that to grow to about 14,500 gigawatt hours in the mid case, up to 16,900 gigawatt hours in the low case. Just like PG&E and the statewide forecast, the mid case is higher than the previous mid cases. This is primarily driven by higher growth for Edison, both in the residential and the commercial sectors compared to previous forecasts.

Overall, compounding the annual growth rate for solar between 2018 and 2030 is about 10 percent. And the midrange is about 9 percent higher than the 2018 forecast.

Okay. So, now, moving on to San Diego. So, for San Diego, estimated PV generation in 2018 was about 1,700 gigawatt hours. We forecast that to go to about 4,100 gigawatt hours in the mid case, and as high as 4,600 gigawatt hours in the low energy demand case.

Now, San Diego has a different curve to it and I'm going to get into that in the next slide. So, one of the trends that becomes evident, when you compare different utilities, is starting at where the baseline penetration rate for PV is, is kind of determining how fast or how slow PV grows. So, Edison had the fasted growth rate in the State over the forecast period, but that's because they had the lowest penetration rate of solar in 2018.

San Diego is on the opposite end of the spectrum. They currently had the highest penetration rate of solar compared to any other utility, but they have the slowest growth rates. And that's just because, especially in the low energy demand case, they're kind of saturating the market, especially in residential solar. And since the mid case is an average of the low and high cases for our PV forecast, part of that is being translated into what you see in the mid case, which is shown in this graph.

So, in this case, you can see strong growth in the residential sector through 2021, people taking advantage of the tax credit. And then, essentially, a leveling off of growth in the residential sector.

But in the commercial sector, you still see growth happening, and that leads to the funky curve from the previous slide.

So, okay. Finally, I'm going to move on to the POUs, although we already discussed LADWP. So, in 2018, energy generated from PV was about 486 gigawatt hours. And in the mid case, we forecast that to go to about 1,080 gigawatt hours. That's about a 20 percent decrease from the previous forecast. And the vast majority of that decrease does come from how we are modeling AAPV and the effect of that slower growth rate and new household growth.

So, if, for the revised forecast we have revised growth in households, then that could go back up. But currently, the difference that we're seeing is in the residential sector for new home construction.

So, here's a chart of the sector breakdown for LADWP. We don't really see, unlike the other, the three IOUs, we really don't see PV installations in nonresidential and noncommercial sectors, but the vast majority of the PV installations are in the residential sector. And the growth in households is affecting this, essentially the forecast this time versus last.

And last of the big five is SMUD. So, in 2018, SMUD had about 320 gigawatt hours of PV generation. In the mid case, we see that going to about 1,130 gigawatt hours. In the low case, as high as 1,470 gigawatt hours. And SMUD has a fairly high growth rate. Part of that has to do with currently they have rather low PV penetration compared to the IOUs, so they just have more room to grow.

And I believe I'm channeling my inner Cary Garcia, but overall SMUD's territory is growing faster economically and population-wise, compared to like the other areas, so that leads to faster growth as well.

So, that concludes the planning area forecast. So, I wanted to conclude, briefly by going over the next steps for the PV forecast and for the self-generation forecast. But if you have any questions on what I've presented, feel free, okay.

COMMISSIONER MCALLISTER: So, I'm good for now, thanks.

MR. KONALA: Okay. We have several updates in mind for the revised forecast and moving forward. The most important part for the 2019 revised forecast is to do an updated energy storage forecast. We did do an update for the preliminary, but we did not change any methodology. For the revised forecast, we hope to come up with methodological changes.

Basically, right now, our energy storage forecast does a trend analysis of recent trends and we just project that out to 2030.

For the revised forecast, we hope to get feedback from stakeholders, especially in the workshop in late September, that Nick had referenced. And we're looking to get more information on energy storage profiles. And with this information, we are hoping to do modeling changes where we do forecasting based more on like the financial metrics, and not just the trend analysis. But this is ongoing work. So, probably, we'll have a lot more information in that workshop in late September about it.

COMMISSIONER MCALLISTER: So, on an hourly front, so I think that's great. I mean, there's a really interesting discussion that, actually, I'm not sure how we get past sort of opinion, without really seeing what the marketplace actually does. But how people actually use these batteries, how they dispatch them. How they -- you know, do they actually follow economic logic or do they, you know, do kind of a, you know, more behind-the-meter just storing their solar when they've got it, or do they arbitrage out there somewhere.

So, we need to think about who we want to inform that discussion in the near term to try and anticipate what's going to happen.

But on the solar front, what are we doing on the hourly front? You know, obviously, solar's more predictable, but are we looking at how that maps onto the hourlies and, you know, the peak shift and all that? What status is that discussion in or that part of the analysis?

MR. KONALA: Okay. So, we have hourly generation profiles. We currently used profiles from E3, which was a confidential study that they did for the CPUC, I believe in like 2013, 2014, based on about five years' of historical generation.

COMMISSIONER MCALLISTER: That's the production profiles of PV?

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: Yeah. So, we have that information. We incorporate that and we provide a project of historical -- sorry, hourly forecasts. And then, that gets fed into the general California Energy Demand Hourly Model. But the hourly numbers are only incorporated for the IOUs. For the POUs, we just use a peak factor.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: So, there's a different methodology depending on whether it's an IOU or a POU.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: So, in terms of PV generation profiles, and I have this later in the slide, there -- we -- so, the data is a little bit old and it is confidential, so we can't share it out. But we're looking into maybe getting update PV generation profiles. Unfortunately, a lot of the work for the preliminary forecast went into just looking at historical data from that new, 1304-B dataset. So, a lot of the modeling work we wanted to get to on PV generation profiles didn't get done for the preliminary. And there probably isn't enough time to get it done for the revised. So, we're hoping it will be part of the 2020 update for the new PV generation profiles.

COMMISSIONER MCALLISTER: Yeah, okay. I mean, NREL, I see NREL we've got coming up next. But on a different topic, NREL also has tools to do the modeling, production modeling, you know, based on satellite data and stuff, so it's not based on monitored data. But if -- maybe we could do a project to see whether they're that different. And that could actually save some effort if we could model and be pretty much right on. I don't know, just a suggestion.

MR. KONALA: Yeah. The datasets that NREL has, that they use to power their PV Watts application, is one of the thing we're considering for the new PV generation model.

COMMISSIONER MCALLISTER: Okay, great. Thanks.

MR. KONALA: And then, my final slide, which I'm just going to -- so, an update on the NREL model that we're contracting with NREL to adapt, their DGen model for use, for the State of California. So, that work is ongoing. NREL is going to present the preliminary results today and then, they'll come back in December and present some revised results, as well.

But modeling work is going to be ongoing between now and then, and maybe even after the revised forecast.

And then, I've presented this slide before, so I'll be short. But, hopefully, our hope is to have staff running this model by the next IEPR forecast in 2021. So, with that, that concludes my presentation. And the details about the NREL model, I want to leave it up to Kevin McCabe, of NREL, to describe when he's up here.

COMMISSIONER MCALLISTER: Okay. All right. Thanks, Sudhakar.

MR. FUGATE: Okay. So, our next presenter is Kevin McCabe, with NREL, to talk about dGen.

MR. MCCABE: Good afternoon. My name is Kevin McCabe. I'm an analyst at the National Renewable Energy Laboratory, in Golden, Colorado. Today, I'll be presenting our preliminary results for our rooftop solar forecast and model validation study, for which we've been contracting with the CEC for the past year and a half, or so.

Quickly, I'd like to thank members of the dGen team, Paritosh Das, Ben Sigrin, and Trevor Stanley, without whom this work would not have been possible.

So, for those unfamiliar, NREL has been contracted by the California Energy Commission to adapt our DER adoption forecast model for the State of California. That model is called the Distributed Generation Market Demand Model, or dGen for short. I'll touch a little bit more about some of the higher level details of the model on the next slide.

But to introduce today's talk, I note that we'll be presenting on two distinct aspects of the project to date, namely very new work. The development of a new methodology to calibrate and validate dGen's predictive performance. And this is done by defining a historic period, in this case the years 2008 through 2016, and understanding how dGen would have predicted or, rather, the amount of adoption dGen would have predicted for that backcasted portion of the model.

And this gives us the sense of not only the accuracy of those historic periods, but also gives us confidence in the model moving forward in the forecast portion.

And speaking of forecasts, that is the second aspect of the results presented today, our preliminary forecast for distributed solar generation in the State. Noting a few updates relative to last year's DAWG meeting, which was kind of the last major iteration of the model, namely we have increase of spatial resolution, not only in the ability to ingest inputs, but also increase spatial resolution of the outputs, as well.

We've also been looking into improved resolution of emerging market segments. Think multifamily buildings, renter occupied buildings, anything that's the nontraditional, non-single-family owner-occupied segment. And, of course, we've been incorporating, as they roll out, the net metering 2.0 features throughout the IOUs including, of course, the transition to time-use tariffs. And other features, including non-bypassable charges, interconnection fees, et cetera

I mentioned dGen is our adoption forecast model. It is capable of forecasting the adoption of distributed PV or solar, but we also have modules for behind-the-meter storage, wind, and geothermal as well, think geothermal or ground source heat pumps. And this forecasted adoption can be done by region and sector through 2050, though today we'll be looking only through 2030.

dGen is in the family of agent-based models and is capable of simulating complex, consumer decision making processes. It gets at understanding the behaviors that consumers exhibit and some of the decisions they make when considering adopting distributed generation technologies.

dGen also sits on a rich amount of spatial data, which we intersect a number of these spatial layers to better understand when and where adoption occurs in a given region. This graphic on the right gives you a sense of what that might look like. This was from some recent analysis where we were looking at the tradeoff of the economics of a distributed wind versus a distributed solar, or rooftop PV project throughout the State.

The panel on the top right shows the solar resource in the State. The panel on the bottom left shows the county level electricity consumption in an annual term. And then, the bottom right panel is a metric we call the solar siting availability. It just gives us a sense of the percentage of rooftops in a given area that are suitable for rooftop solar siting.

And, really, all these layers combine and intersect to inform that top left panel which is, in this case, what we call economic potential. I get back to that definition in a few slides. But just, the gist of this is that we have a number of intersecting spatial layers on top of other layers, on top of other data, and all these intersect to give us a sense of results of adoption or potential for the State.

And this is important because within the team we're really starting to ask ourselves how accurate is our model? How accurate is any adoption forecast model? And a big motivator for that is cost, naturally.

This is some work performed by colleagues at the lab, which showed that the cost of mis-forecasting distributed generation resource can be quite high, though certainly varies greatly with the amount of actual error and the DPV penetration level.

Here, this chart is a little busy, but I'll walk through it. Here, on the X-axis we're looking at the systematic error in a 5-year forecast for a given utility or region. The Y-axis shows an increasing level of DPV penetration over a 15-year period as a percentage of total generation. And the V-axis, or what the colored regions are showing, is the change in total present value system cost relative to what a perfect forecast would have been.

And so, there's some interesting regions on the graphic here, but perhaps the most critical is in the top left corner, where we see a hypothetical region, a hypothetical utility with an 8.5 percent DPV penetration level that is under forecasting at a 100-percent rate. In this case, we are looking at upwards of $6.8 million per terawatt hour of electric sales, that is those costs that re incurred due to that mis-forecast.

And so, maybe that's not a great example. You would expect that utility, expecting 8.5 percent penetration, would expend a little more effort and cost into their forecast. But, nonetheless, it just illustrates some of the motivators and drivers for understanding DR adoption.

And, certainly, we've looked at the literature and tried to better understand these drivers. But a lot of literature base is largely oriented around explanation and not necessarily prediction of the adoption itself.

So, that leads us to where we are today. The methodology for adapting our dGen model for the State of California. I mentioned we're starting to look at a backcasted period, starting in 2008 and running through 2016 as our historic period. And what we're really attempting to get at is economic calculations and, ultimately, adoption projections for those historic years.

And so, the chart on the left gives you a sense of what those economic calculations might look like. This is the model of the payback period. The payback periods are coming out of dGen for that historic period and looking forward to 2025. And from this, you can start to see some of the trends that you might expect, like decreasing solar technology costs over time. Perhaps you can see the effect of the ITC phase out, the effect of net metering 2.0 rollout, et cetera.

And this gives us confidence and leads us to the chart on the right, which is what we're trying to match, what we're trying to fit the dGen model to, which is the known annual installed DPV capacity in the State, going as far back as 2000 in this chart but, of course, 2008 is the start of our historic period.

And so, the effort, the recent effort we've embarked on with the CEC is to try to understand how we can better calibrate the model to match that historic data. And so, to that end, dGen was calibrated with suite of scenarios to better understand the effect of two distinct aspects on the fit to historic data.

So, we looked at the effect of the geospatial resolution. We do have county level adoption totals, historic adoption totals. And so, we wanted to look at the effect of keeping, or rather fitting the model using county level data versus aggregating that up, and looking at what the fit would be at the State level.

And we also looked at the influence of historic payback periods as well, essentially, the influence of historic economics on the goodness of fit of model to actual data. And so, what we found is that in general the fit to historic adoption data is better when the influence of historic payback periods is ignored.

And this is, perhaps, a bit counterintuitive. You would expect economics are, and indeed are, one of the main drivers for adoption of any distributed generation technology. And the other aspect, the effect of geospatial resolution we found to be minimal, though the best fit in this suite of scenarios is looking at county level resolution.

And so, the table on the right shows you some of the numbers related to these scenarios that we ran, where indeed the county level resolution, plus the no-payback influence scenario gave us a normalized root mean square error of about 13.7 percent. And so, that corresponds to the orange line there, in the chart on the left.

You know, and I should mention this is very new work. We're continuing to refine these methodologies and processes. I mentioned that there is some counter intuitiveness to the fact that our best fit came from a scenario where we are not considering historic economics. As I mentioned, we're continuing to understand this process and potentially refine these results to include -- to improve them in general.

And so, what this does is this calibration and validation study gives us confidence, then, moving forward looking at our adoption forecast. Where we are again looking at a suite of scenarios, this time looking forward, to show the sensitivity of projected adoption to certain variables or conditions, including different

PV cost schedules, as well as the demand scenarios that the CEC has run in their analysis.

So, anchoring our scenario analysis is the mid case. This is, essentially, our central assumptions of things like technology costs, the growth rates for economics and demographics, as well as the growth rate of electricity, retail and wholesale rates that is.

And then, surrounding those in the demand scenarios are the high and low demand scenarios, which we've attempted to align, as best as possible, with the CEC high and low demand scenarios. Though, certainly we note that the frameworks of the two different models are quite distinct and, therefore, some of the inputs aren't exact though, as I mentioned, we have attempted to align them as best as possible.

Two other scenarios that we're looking at as well, on top of these demand scenarios, are looking at the effect of differing PV cost schedules over time. And these are the high and low PV cost scenarios that you see here. And before I move on from this slide, I note that a lot of our data and projections of things like costs and rates come from NREL's annual technology baseline, or ATB effort. There's some details on the site there, atb.nrel.gov, and I'd be happy to answer more questions at any time. But this just gives us a sense of what technology costs look like into the future, under different scenarios and, by extension, what the retail and wholesale electricity rates look like for that given mix of generation technologies.

And so, here are the preliminary results for the adoption forecast, showing the sensitivity to those scenarios that I mentioned. We found that the sensitivity of adoption to the demand scenarios is actually quite modest. Noting that the range between the high and low scenarios in 2030 is only about 3.1 gigawatts AC.

And we're starting to understand how these demand scenarios are being internalized in the model. And what we're starting to understand is that the influence of electricity rate growth is actually much greater than that of the load growth. And part of that is in part due to the way that dGen calculates system sizes.

dGen takes, as the max system size that a consumer can size their system as the minimum between offsetting 100 percent of their annual electricity load, the minimum between that and developing -- or, rather, citing solar panels on their total developable roof area. And so, you can expect in a scenario where load is decreasing over time, that max PV size is also decrease and then, by extension the selected, the ultimate selected system size would also decrease.

And so, we're starting to understand how these scenarios are acting within the model, but that's what we believe to be a major driver is the electricity rate growth.

COMMISSIONER MCALLISTER: So, let me just make sure I got that clear. So, in a case where you've got a roof that's big, like larger than an F or a net zero kind of scenario, you're assuming that somebody -- that, basically, the size would be equivalent to net zero?

MR. MCCABE: I think that, considering net zero effects may be going a little bit too far.

COMMISSIONER MCALLISTER: Did you say 80 percent, or I'm sorry.

MR. MCCABE: So, we are looking at the minimum between the maximum PV size. This is not the size that is actually selected.

COMMISSIONER MCALLISTER: Yeah.

MR. MCCABE: The maximum size that a consumer can select is either covering 100 percent of the developable roof area, for their roof --

COMMISSIONER MCALLISTER: Yeah.

MR. MCCABE: -- or offsetting 100 percent of their annual load.

COMMISSIONER MCALLISTER: Oh, okay. So, you're not assuming that everybody who can offsets 100 percent of the load.

MR. MCCABE: Correct.

COMMISSIONER MCALLISTER: You're just saying that that's the maximum.

MR. MCCABE: That's correct.

COMMISSIONER MCALLISTER: Okay. Okay, I missed that part. So, great, thanks a lot.

MR. MCCABE: And that system size selection process then looks through between zero and that max size --

COMMISSIONER MCALLISTER: Oh, okay, gotcha.

MR. MCCABE: -- and selects the one that has the best economics.

COMMISSIONER MCALLISTER: I gotcha. Thanks for that.

MR. MCCABE: Sure. So, that was kind of a discussion around the high and low demand scenarios.

The PV price scenarios, we note that although California has been a pretty mature market for solar throughout the years, PV prices continue to show a pretty significant effect on projected adoption.

In this case, the range between the high and low PV cost scenarios in 2030 is more than double what we saw in the high and low demand scenarios. Specifically, 7.6 gigawatts AC in 2030. Although, I should note that the inputs, the actual PV installation costs for those two scenarios are quite distinct as well, where we're looking in the high PV scenario at an installed cost of $3 per watt. In the residential sector versus in the low PV scenario about $.50 a watt. So, you can start to see and expect that large ranges in the inputs could result in larger ranges in the outputs, naturally.

There's a lot more numbers and results by planning area, but this is a single slide that starts to get at these results. And so, what we note is that, perhaps unsurprisingly, the major IOUs will continue to lead the way with adoption.

We are estimating in the PG&E and Edison planning areas about 10.7 gigawatts AC of cumulative adoption by 2030. And that's followed up by San Diego at 2.8, SMUD at 1.5, LADWP at 1.4, and all other planning areas at 0.6 in 2030, in the mid case scenario.

You know, and despite the sheer size advantage, if you will, of PG&E and Edison territory, we do note that economics at the granular level, when you start to dig into the granular results things like full retail net metering for the non-IOUs, other utility-specific incentives really do show up in those economics. And so, statewide, we're looking at quite a bit more -- quite a bit of favorability for adopting PV throughout the years.

I mentioned that the start that we're starting to look into some of the nontraditional market segments. Traditional being just the single-family, owner-occupied segment. And new datasets that have been developed at the lab have enabled some preliminary analysis of these markets.

In particular, the replica dataset, on the right there, shows -- or, rather gives us census tract level data for things like solar technical potential. Rooftop area, for example, we use Lidar data to estimate rooftop area. We have census tract level data for things like building counts, customer counts, et cetera.

And so, what this really, finely resolved dataset allows us to do is understand what these emerging market segments might look like. And though, you know, moving past some of the pure economic calculations into what is ultimately adopted certainly introduces some uncertainty.

And so, what we've done here is instead of report adopted totals for these emerging segments, what we're doing is looking at a metric that we call economic potential. And this is defined as the amount of PV capacity that exceeds a given rate of return. In essence, PV systems that exhibit a positive net present value. There are a number of financial inputs into the model, and so these are all dependent on those as well.

But what we note is that the amount of economic potential in the nontraditional market segments could add an estimated 45 gigawatts AC of potential statewide, in 2030. And this is on top of nearly 80 gigawatts of potential in the traditional single-family, owner-occupied, and nonresidential sectors.

And so, certainly, there's a lot more work to be done to understand what adoption actually looks like for these emerging segments. Things like ownership issues, HOA considerations. All of these things need to be taken into account before we have a little bit more confidence in understanding what adoption looks like.

But in a pure economic sense, there is quite a bit of promise for these emerging segments.

I will wrap up. I have one more slide after this, but this is a look at some of the geospatial trends of adoption. This is looking at our mid case scenario in 2030. And this kind of harkens back to what I was discussing in the beginning, where a number of multiple spatial layers start to intersect and to inform where and when adoption occurs in the State.

In this case there's, perhaps, no surprise that many of the Southern California counties are leading the way at the county level resolution. We're starting to see adoption follow trends of strong solar resource, not surprisingly. Areas of high load, not surprisingly. So, starting to intersect many of these different layers and inputs result in something like this.

An so, here we see Los Angeles, San Diego, Riverside, Orange, and San Bernardino Counties rounding out the top five by installed capacity.

I'll quickly wrap up here, just to kind of conclude some of the discussion I just gave. So, the new effort to calibrate and validate the model has really illustrated some of the major influences on how well we can fit model data to known historic data.

And for this preliminary study, we're looking at two distinct aspects, namely the effect of historic payback periods, as well as the geospatial resolution of known historic adoption totals versus modeled. And we're starting to better understand other datasets, other attributes of the model that can potentially improve the fit.

And so, this is very new work and we're excited to see it through to potentially see better fits of model to historic data.

We found, looking at the forecast data, that there is pretty modest sensitivity of adoption to the demand scenarios, but a much more acute sensitivity to PV prices. Perhaps, unsurprisingly, by planning area we note that the major IOUs are projected to lead adoption though, certainly, economics for the non-IOUs are quite favorable, still.

And then, finally, looking at emerging markets, things like non-single-family, owner-occupied market segments do show quite a bit of promise, though we note that further data and analysis tools are certainly necessary to be able to model these segments more accurately.

So, with that, I will wrap up and I'm happy to take any questions.

COMMISSIONER MCALLISTER: Yeah, I have a couple questions, actually. So, are you looking at incorporating storage into this, like sort of solar plus storage and how that impacts the economics and, therefore, the adoption?

MR. MCCABE: Yeah, that is certainly a part of this partnership. To date, we have not run any solar plus storage modeling scenarios, though dGen is capable of doing so. We're kind of -- outside of this project, we're starting to look at overhauling the major module, which calculates bills, and incorporates technologies like solar and storage together.

COMMISSIONER MCALLISTER: Uh-hum.

MR. MCCABE: And so, we're starting to get a little bit more confidence in being able to present those results. Though, you mentioned in Sudhakar's presentation that there are some questions as to whether the strategy should be economic dispatch versus arbitrage.

COMMISSIONER MCALLISTER: Yeah.

MR. MCCABE: So, we, as well, are starting to understand how best to report adoption estimates for behind-the-meter storage.

COMMISSIONER MCALLISTER: Yeah, that's great. And we're having that conversation in the context of the building standards themselves, right, so outside of the forecast, in a different arena. But, you know, how we can justify including -- or, how we include storage in the building standards really depends on what the options are for people to use it and dispatch it.

MR. MCCABE: Certainly.

COMMISSIONER MCALLISTER: You know, developers aren't going to put it in a new home, if people don't want it or if we limit how they can use it.

And so, the second question, are you looking at

-- well, sort of related to the first. Are you looking at production curves, you know, sort of hourly or, you know, interval capacity shapes or production shapes for the PV.

MR. MCCABE: Yes. Right, yeah, we do. So, as Sudhakar mentioned, we have been provided with generation, 8760s of generation by the IOUs and -- mostly the IOUs. But NREL also has done quite a bit of research into typical meteorological year data --

COMMISSIONER MCALLISTER: Yeah.

MR. MCCABE: -- MY data. We've, across the lab, have been overhauling to TMY3 recently. We've also started looking into the benefits and challenges of using actual meteorological year data. There's, perhaps, some benefit to using that actual data to better understand weather effects, et cetera.

COMMISSIONER MCALLISTER: Yeah.

MR. MCCABE: So, when we use that TMY3 data, we have a lot more measurements, a number of weather stations throughout the State of California and hundreds throughout the U.S. that we can potentially use to model or, rather, give generation, hourly generation profiles.

COMMISSIONER MCALLISTER: Is NREL putting any emphasis on SAM, anymore?

MR. MCCABE: Oh, yeah, a ton.

COMMISSIONER MCALLISTER: Okay.

MR. MCCABE: The System Advisor Model?

COMMISSIONER MCALLISTER: Yeah, yeah, because that seems like a perfect model to generate some of these curves, and then calibrate those against reality, and then see if you can just use SAM going forward.

MR. MCCABE: Yeah, SAM has been under some pretty major development in the last years. It's open source, it's capable of simulating a number of different generation technologies. That's actually, when I mentioned that we're looking to overhaul some of our internal calculations, the SAM module for bill calculating is something that we're hoping to include because --

COMMISSIONER MCALLISTER: That would be great.

MR. MCCABE: -- they have a much better representation of storage than --

COMMISSIONER MCALLISTER: That would be great.

MR. MCCABE: Yeah, so stay tuned.

COMMISSIONER MCALLISTER: Yeah, okay. I'm sure we'd love to collaborate on that.

MR. MCCABE: Great.

COMMISSIONER MCALLISTER: Yeah. Thanks for your presentation.

MR. MCCABE: Thank you.

COMMISSIONER MCALLISTER: Yeah, good. All right, thanks.

MR. FUGATE: So, next up is Chris Kavalec, who's going to get us back on track with a 5-minute presentation on all of his hourly work.

MR. KAVALEC: Good afternoon. I am Chris Kavalec from the Energy Assessments Division. And I'm going to talk for five minutes or maybe a little longer about our hourly load forecasts, provide some results for peak projections for the IOUs. And the IOUs, if they want to have specific comments about these peak forecasts, they can fold that in with the comments they provide when Cary does his planning area presentations a little later. And then, I'm going to talk a little bit about next steps.

Okay, the reason that we are doing hourly load modeling, which we started to do about three years ago, is that the darn peak hours won't stay put anymore because of all the demand modifiers, particularly PV. And so, therefore, to properly model peak and capture this so-called peak shift that is now happening, one needs an hourly analysis to account for it properly.

Also, since we're doing hourly load forecasts, we can now provide monthly peaks at the TAC level, transmission access charge level, for resource adequately purposes for their year-ahead analysis, to be used as a benchmark as they do their individual LSE year-ahead projections.

And also, the California ISO uses our hourly results in their flexibility studies, looking at 3-hour ramp ups, 3-hour ramps over the course of a year.

I won't give a lot of technical details. I'll just briefly review what this model is all about. What we're estimating with this hourly load model is what we call consumption load ratios, meaning hourly consumption divided by the average of hourly consumption over the course of a year.

Now, I have consumption in quotes there because it's defined a little bit differently than we typically define consumption. What it is, in this context, is sales, plus line losses, plus PV, plus avoided losses from PV. And it does not include non-PV self-gen.

It's set up this way because our model is based on the EMS data from California ISO, which includes hourly data, which includes losses.

So, these consumption load ratios are specified as a function of weather and calendar variables. And then, once these are estimated, we take average hourly consumption, as I've defined it, from the traditional IEPR long term forecast for each year, apply it to those load ratios and that gives us hourly, what we call unadjusted consumption for each hour and each year.

Okay. We then adjust those unadjusted consumption numbers by incorporating hourly EV load, hourly climate change impacts, residential TOU, and a couple other minor consumption adjustments for a couple of the smaller LSEs.

And then, we subtract off hourly PV generation to give us baseline hourly sales forecasts. And that should say baseline hourly sales plus losses forecasts, the way we've defined our metrics here.

And the maximum of those baseline hourly sales forecasts is what we call the net peak for the year, or the net baseline peak for the year.

We are currently doing our hourly load forecasts at the IOU TAC level, the three IOU TACs that we're familiar with, transmission access charge areas. And then, to round out CAISO, we also do a separate model for Valley Electric. A small area, but it's considered a TAC and it's included in CAISO.

Then, when we get to our revised forecast, later in the year, we will also be incorporating hourly AAEE, as Ingrid mentioned earlier, to give us our managed sales forecasts by hour -- sales plus losses forecast by hour. And from that, get managed peaks for planning purposes.

Some updates versus the last time we did an hourly load forecast for 2018. This time, we did a separate estimation of pumping loads, using a fairly simple regression model, where for each hour we specify the amount of pumping by month, and day of the -- weekday versus weekends, and holidays.

And for Northern California, this means Department of Water Resources. And for Southern California, this means Department of Water Resources and the Metropolitan Water District.

The reason that we wanted to estimate these separately is that pulling out the pumping loads from the rest of the load just, hopefully, gives you more precise estimates of the impact of weather and calendars on the rest of the load, since pumping load is a little bit different, obviously, than the rest of the load.

We wanted to model DWR and MWD separately for Southern California. But the data we have now for MWD isn't very good. So, what we did was to model DWR and MWD together, using the EMS pumping loads provided to us from California ISO, which is a combination of the two.

We have new hourly EV loads and load shapes, a new PV forecast, as Sudhakar mentioned earlier. And, when we get to the revised forecast, we'll have new AAEE numbers.

A little bit about the hourly EV loads and load shapes. For the last couple of forecasts, we used hourly EV profiles from Lawrence Berkeley, based on a household travel survey.

For this forecast, we are using load shapes developed by ADM Consulting as part of our load shapes and HELM project, that I'll talk about a little bit more, later. And these profiles are based on actual vehicle charging data from ChargePoint and from Joint IOU EV Load Research reports.

And here's a typical load shape that we can compare to what we had in the previous two forecasts. This is for Edison, for a June weekday in 2030, but it's fairly typical of the shape that you'll see for the other IOUs, and different times of the year.

So, we have, in dark blue, the new shape from ADM and in red, the shape that we used in the last couple forecasts from Lawrence Berkeley. And you can see the big difference there is that, according to ChargePoint, there's more charging in the middle of the day, significantly more.

Oh, I should mention that what this is showing is the percentage of load by hour, the percentage of daily load by hour. That's what's on the vertical access there.

And then, the other big difference is that when we get to the --

COMMISSIONER MCALLISTER: So, is that an 8 percent or a .08 percent?

MR. KAVALEC: Oh, yeah, it's -- okay, proportion of load, daily load by hour.

COMMISSIONER MCALLISTER: Oh, okay. Okay, so it's --

MR. KAVALEC: Yeah. Sorry.

COMMISSIONER MCALLISTER: Okay, got it.

MR. KAVALEC: So, when we get to the late afternoon/evening hours, where we are under residential -- the residential TOU pricing regime, you see a much bigger drop off in the new load shape versus what LBNL was estimating, previously.

And this means that the elasticity of demand relative to the peak, non-peak TOU price, or elasticity, or sensitivity is much greater in the ADM load shape analysis.

Okay, some results. First, for California ISO, which is the sum of the individual IOU TACs, plus Valley Electric. You can see at the beginning of the forecast period that drop off. And that reflects the consumption and sales drop off from 2018 to 2019, that Cary mentioned earlier. And that comes about because of the weather adjustment, going from the historical to the forecast period.

And then, the big lump of additional efficiency program savings in 2019. And also, for PG&E, specifically, we assumed relatively heavy amount of rainfall in 2019, based on the early months of 2019, which meant a lot less groundwater pumping. So, the drop off in consumption and in net peak is greater for PG&E compared to the other IOUs for that reason.

Okay. And that's an assumption, that amount of heavy rainfall year that we'll revisit for the revised forecast.

Okay. A drop off at the beginning of the forecast period. And then, you see in the mid and low cases, so the red is the 2018 mid forecast, the high, mid and low are green, dark blue, and purple, respectively.

In 2020 to 2021, in the mid and the low cases, you see another little drop off there for CAISO. And that's happening -- that comes from PG&E, and I'll talk about that when we get to PG&E in a minute.

After that point, after 2020, a little bit less growth in the peak compared to what we had in 2018, comparing the two mid cases. And that's because of the additional standards and a little bit more PV this time.

This graph is meant to show the impact of accounting for the peak shift, which I mentioned earlier, our peak hours are shifting to later in the day mainly because of PV.

So, the red line there, at the top, is our consumption, peak consumption as consumption defined as I did it earlier. And then, subtracting off PV from that red line, we go down to our net peak, which is given by the green line. Accounting for the change. potential change in peak hour, as we do that.

Now, had we not accounted for the change in peak hour and assumed that the peak was happening at the same hour as the consumption peak, the red line, we'd go all the way down to the blue line and have a much lower peak. So, that by 2030, for CAISO, we have a peak shift impact of over 6,000 megawatts. So, that shows how important it is to account for peak shift. We would be underestimating or under-forecasting the CAISO peaks by around 6,000 megawatts by 2030.

This is another way of showing the same thing, the peak shift. A little bit of a messy graph here. But this is attempting to show the impact of all the individual demand modifiers that are part of the hourly load model. So, starting with the red line, the bottom line in that group of lines there. that's the unadjusted consumption that I mentioned earlier.

We incorporate electric vehicles, pumping, residential TOU, climate change impacts, and we end up at the yellow line there, at the top. So, that shows a consumption peak of around 56,600 megawatts.

Then, we subtract off our PV impacts by hour, for that peak day, and that gets us down to the black line. Again, if we assumed that the peak hour did not change and kept the same peak hour as we assume for consumption, we drop all the way down to 43,000 megawatts.

However, you can see that the peak hour for that black curve or the peak for that black curve is all the way -- the right there, is all the way up over 49,000 megawatts.

Okay. So, again, accounting for the peak shift means your peak is about 6,000 megawatts higher than if you didn't account for the peak shift.

I mentioned this hourly load model being used for -- to develop monthly peaks for resource adequacy, year-ahead analysis. So, looking at 2021 here, the baseline that peaks by month for CAISO, for the mid case, and red is the forecast from 2018, and in dark blue is the new forecast by month. And, not surprisingly, the new forecast by month is a little bit lower because of lower consumption and lower peaks, as we saw earlier in the graphs. And you can see that the gap between the red and the blue is a little bit higher in the warm months because of the additional PV. PV having more of an impact during the warmer months.

And I should say, again, this is not the end of the story because these two graphs, like the other results we've shown today, do not incorporate AAEE.

Okay, PG&E. Again, the drop off in consumption, which is from 2018 to 2019, which is higher than the other IOUs because of the assumed reduction in groundwater pumping.

And then, I mentioned for CAISO you see a drop off in 2020 to 2021. That's coming from PG&E in the mid and the low cases. And what's happening there is we have a big jump in PV adoptions in that year. And that happens to be the year before -- or, the last year before the tax incentives, the tax credits end for PV.

And then, after that, more steady peak growth as the rate of PV adoption falls below what it was in the earlier years. A little bit less growth comparing the two mid cases in red and in dark blue for the new forecast. A little bit less growth, again because of the impact of additional standards and a little bit more

PV.

COMMISSIONER MCALLISTER: Can you comment about sort of what the end state of where the peak ends up? You know, the peak can't get pushed back by solar forever, right? And we've sort of been inching it 15 minutes here, you know, and an hour there back into the evening. You know, where does it settle, do you think, in terms of the end state?

MR. KAVALEC: Well, it depends on what time of the year the peak happens.

COMMISSIONER MCALLISTER: Uh-hum.

MR. KAVALEC: But if it's September, which is fairly common for -- recently, for CAISO, as well as for Southern California, by the time you get to 8 to 9 in the evening, you have almost no PV generation.

COMMISSIONER MCALLISTER: Yeah.

MR. KAVALEC: So, that's where the peak shift basically is going to have to end, at basically 7 to 8. So, your peak could move to 7 to 8 p.m., but beyond that you have no more, or a trivial amount of additional PV, so you don't get any more peak shifts beyond that time.

COMMISSIONER MCALLISTER: Right, so that makes sense. I guess, as we -- you know, the next step is to say, okay, well, how do we deal with the ramp leading up to that peak, and in terms of just calculating scenarios around storage, around load shifting, demand flexibility? It seems like we need to start putting some numbers to that. I mean, I'm not saying maybe formally in the 2019 forecast, but probably some strategizing about how we're going to analytically do that, if you guys aren't already doing that. I don't know.

MR. KAVALEC: And for PG&E and San Diego, we seem to be pretty close to that limit by the end of the forecast period.

COMMISSIONER MCALLISTER: Uh-hum.

MR. KAVALEC: It's moved to 7 to 8 p.m. Well, again, it depends on the time of the year and what scenario that you're looking at.

And with Edison, which I'll talk about in a minute, which is not quite as far, so it still has a little bit more peak shifting that can happen. At least, according to our forecast by 2030.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. KAVALEC: Again, looking at the peak shift impact, the net peak is in green. The peak shift impact, shown by the difference between green and dark blue for PG&E, which reaches around 2,800 megawatts by the end of the forecast period.

And the other day, we were comparing our peak forecasts with those developed by the PG&E staff, and their growth rate for their net peak is much lower. They have, basically, a flat peak forecast. But they do consider the peak shift and the peak shift impacts. They do, do an hourly analysis.

So, the question was, maybe their peak shift impact is not as high as what we're assuming. So, we asked them to look into that and to see if that explains the difference. And if it does, then we need to talk maybe a little bit more about our respective hourly methodologies to see what is different.

Again, showing the load modifiers, consumption peak, 25,200. If we didn't consider the peak shift, all the way down to 19,000. Considering the peak shift, we're up to 21,800 for our net peak.

For Edison, again not as much of a drop off at the beginning of the forecast period. We don't have that groundwater issue and the weather adjustment is not as large as for PG&E.

2020 to 2021, we do have a little spurt in PV, but not as much as for PG&E, so the line's just flat and they don't decrease from 2020 to 2021, like for PG&E.

And then, beyond that, like PG&E, a little bit less growth because of additional committed standards and a little bit more PV compared to last time. And comparing the two mid cases, red and dark blue.

We've found this phenomenon in the last two forecasts, in our hourly analysis, and that is that the peak shift seems to be a lot lower for Edison than for PG&E. You see the peak shift impact is only about 500 megawatts there by the end of the forecast period, compared to 2,800 for PG&E. And I'll talk about the reasons for that in a minute.

Looking at the load modifiers, consumption peak 28,500, drop down at the same hour to 23,500 when you include PV. Peak shift brings us up to 24,040.

So, why do we have a big difference between Edison and PG&E? First off, PG&E has a lot more PV relative to the size of its load, so you have less ammunition for a peak shift.

And the other thing is that PG&E loads seem to stay high later, farther out into the afternoon and evening.

So, this graph here is showing the percentage of the peak load by hour. And this time, I do have actual percentages, not proportions. So, you can see Edison peaking around 2, 3 o'clock there. And then, dropping off more quickly than PG&E, in red.

So, basically, what's going on here, according to my hypothesis, is that when you start losing PV in the late afternoon and evening, when it starts to drop off quickly, for PG&E the total load stays high. So, that means the utility, itself, has to serve more of that load and that means more of a peak shift.

For Edison, in the late afternoon as the PV starts dropping off quickly, the load also starts dropping off quickly and, therefore, you have less load having to be served by the utility, less of a peak shift.

So, it's those two reasons. We've talked to Edison a couple of times about this and discussed this difference. But Edison is not entirely convinced and would like to discuss this further, which we're happy to do. And that will happen shortly after the workshop.

The other thing that Edison mentioned is they think the elasticity of the residential -- or, the impact of residential TOU on electric vehicle load shapes is too high. There shouldn't be as much of a drop off. And they've done some work and gotten some different results for EV load shapes and we're going to talk about that as well, shortly.

Finally, San Diego. The drop off from 2018 to 2019 is coming mainly from the weather adjustment, but we also have the additional lump of 2019 efficiency program savings. Then after that, again, a slightly less growth because of the committed standards and slightly more PV.

Peak shift impact of about 800 megawatts by the end of the forecast period. Shown a different way, peak shift's going from 3,800 to a little bit over 4,600 megawatts for the mid case in 2030.

In case you're interested, this shows the simulation of pumping loads for Northern California, meaning DWR. And it's similar, the same things are going on in Southern California, so I'm just showing one here, one example.

So, I'm showing pumping loads, modeled, simulated pumping loads in a winter month and a summer month, January and July, and then for weekday and weekend.

So, you'll immediately notice that as the DWR attempts to accommodate overall load, they're pumping more on the weekends versus the weekday. And they're pumping more in July, not surprisingly, compared to January. Except during the -- you'll see the July curves, the green and the purple, they drop off pretty dramatically as we get toward the peak hours in the afternoon and evening. And gain, that's DWR accommodating the rest of the loads.

And the same thing happens in January, although at a different hour. Our peaks are happening in the late evening, mainly because of lighting and some heating. But again, DWR is accommodating that drop off by reducing their -- or, accommodating the peak loads for January by dropping off pumping during those hours.

Next steps for the revised forecast. New AAEE, as we've mentioned ad nauseum today. We will, hopefully, have reasonable storage charge discharge profiles, although those will have to come with the caveats that the Commissioner mentioned earlier.

We adjust our peak totals by accounting for a little bit of load-modifying DR. It's not very -- it's DR that we agreed with CPUC should be handled on the demand side. The rest of the DR is handled on the supply side. So, it includes like peak pricing, permanent load shifting, TOU, et cetera.

We have a little bit of that, that we get from the IOU DR filings that they do every April. And so, we adjust our peak amount by the small amount of LMDR. It amounts to, you know, a couple hundred megawatts for CAISO, as a whole. But it is a pain to have to post process that and say here's our peak, however, you have to adjust it to account for load-modifying DR.

So, fortunately, there is, apparently, enough information to be modeled in 8760 for load-modifying DR, so we will attempt to do that.

For the revised forecast, we will have updated residential TOU.

I mentioned climate change, earlier, as one of the hourly demand modifiers. So, what I did the last forecast, in this preliminary forecast was to take our annual climate change impacts and annual peak climate change impact that Cary discussed earlier, and distribute those impacts over the hours in a given year by, basically, assigning more climate change impacts to the higher load days in the summer, when it's hotter. And, also, the highest decreases coming during the winter months to the winter loads that were highest.

Okay. So, basically, I distributed the climate change impacts according to the size of the load, taking into account winter and summer. That's a fairly crude way to do it and we would like to find a more refined way to do this going forward.

Fortunately, Scripps was able to develop hourly temperature projections going out 50 years, consistent with the scenarios that they're already providing us, from which we develop our annual climate change impact.

So, that means that for the revised forecast we will attempt to integrate their hourly temperature projections into the hourly load model, so that we can have a better, more defensible set of 8760 climate change impacts going forward.

The last thing is integrating this with our traditional peak model, which we call HELM, hourly electricity load model, a new version of it, so that's why the 2.0 is there. That new version is the new platform that ADM put together, together will all their new load shapes that we talked about earlier.

So, we have these two methodologies that are designed to do the same thing, develop an 8760. So, the question is how do we integrate the two. When do we use one versus another.

So, just a little bit about HELM. It's a fairly simple methodology. We're taking annual consumption by end use and building type for the residential and commercial sector from our sector models. And for different NAICS groupings for the remaining sectors. For example, chemical industries is one NAICS grouping.

And these load shapes are applied in HELM, and are applied to these annual loads. And then, we aggregate everything up and from that we develop peak load for each year. And then, we adjust that by the amount of self-generation and we get net peaks.

So, we've traditionally used that to do our peaks. And the load shapes are very antiquated. They came from the 90s and early 2000s. And so, we enlisted ADM to develop a new platform and update all our load shapes. And that's what they've done. And the HELM 2.0, the new version, also adds loads shapes for efficiency, generation profiles for PV, electric vehicle charging profiles, as we've discussed with the unfortunate name of EVIL sub-model. And then, this is all done at the forecasting level.

And as I said, this is a nice -- we now have a nice user, hopefully, user-friendly platform for HELM 2.0.

And here are some of the sources. And two points I want to make here. These different sources serve as a starting point for developing the individual end use building type or NAICS grouping load shapes. And then, these load -- preliminary load shapes are tuned to actual IOU interval meter data. So, that just means, basically, you take a specific building type, for the interval meter data you add up all the loads, hourly loads for the individual end uses associated with that building type, see how they match up. Make adjustments if there's a big difference between the two. So, it's basically a way of calibrating the load shapes.

Chargepoint date, as I mentioned, CSI data, as well as other data for PV.

And also, as I alluded to earlier, we think of this as a starting point. There are going to be continual new sources of load shaping formation. Meter data, studies like the Commissioner mentioned earlier, being done by PG&E. So, we have a starting point and as new information, data, and studies become available, we will do our best to update the appropriate load shapes based on that information.

And here, if you're interested in looking at the load shapes report, we have it posted. It explains the methodology, shows a whole bunch of different load shapes and compares them to what we had in the old HELM model and so on.

So, how do we integrate the two? Well, ideally, HELM, this new version of HELM, will provide a reasonable set of 8760 hourly load forecasts for each year. If this is the case, then there are more aggregate hourly load model, the econometric hourly load model would be used as a check, and maybe for some regional studies for regions not covered in HELM 2.0.

The reason I say ideally is because of HELM performs to our satisfaction at the 8760 level, then we will have not only total hourly load forecasts, but we can break that down into the different sectors, and even different end uses.

However, my experience has been that it's very difficult to develop a model, a bottoms up model to properly characterize 8760 hourly loads. And the reason for that is that at the hourly level, as you get more and more disaggregate, there's just more and more noise. So, when you're trying to match historical data or make the output look like historical data, it gets very difficult to do, the more disaggregate the more your model is, the more bottoms up your model is.

I could be wrong, but if this is the case, and we're not happy with the 8760, it's giving us screwy results for some hours or months, well, in that case we can continue to use the hourly load model and then, we could calibrate that each year to the HELM 2.0 annual peaks.

So, we've found that the original version of HELM, even though it didn't perform very well for 8760, it does give us a pretty reasonable peak forecast comparing HELM output to actual history.

So, I'm confident, at least, that we'll have a peak coming out of HELM 2.0 that, as I said, the advantage of that is you can break it down into different sectors and end uses. We'll at least have that and, hopefully, we'll have more. We'll have a full, reasonably, soundly performing 8760 hourly load forecast coming from HELM.

We're now putting it through its paces and we will see, and we're hoping to use HELM in some form. We're planning to use the new HELM in some form for the revised forecast, so we'll keep you posted.

COMMISSIONER MCALLISTER: Oh, okay. So, what about the monthly peaks? So, you're corralled to the confidence in the annual peaks or how are we thinking about, you know, working through the monthly peak issue?

MR. KAVALEC: Yeah, so I think that would be the same. It could be that HELM 2.0 performs well at the monthly level, for monthly peaks, although not necessarily for 8760, let's say.

COMMISSIONER MCALLISTER: Yeah.

MR. KAVALEC: Well, in that case, we could calibrate the hourly load model, the more aggregate model to monthly peaks from HELM.

COMMISSIONER MCALLISTER: Uh-hum.

MR. KAVALEC: So --

COMMISSIONER MCALLISTER: Okay. I'm thinking of, you know, all the other uses for RA, and all those other purposes.

MR. KAVALEC: Yeah, so, yeah, we'll just have to see.

COMMISSIONER MCALLISTER: Yeah, okay.

MR. KAVALEC: We're going to run it through all kinds of different tests and compare it to the hourly load results we have now and, you know, take it from there.

COMMISSIONER MCALLISTER: Yeah, okay. All right, well, great. Thanks, Chris.

MR. KAVALEC: And jerk that I am, I didn't list the names of all the people contributing to the forecast, like Mark did.

COMMISSIONER MCALLISTER: Mark's making you look bad.

MR. KAVALEC: But I will say, I want to thank the 20 or so people that are directly involved in the forecast, including the Transportation folks, the Efficiency Unit, the sector modelers, and our data people.

Okay, thank you.

MR. FUGATE: Okay, the last presentation is Cary Garcia, again, to review planning area forecasts.

COMMISSIONER MCALLISTER: Just a reminder, I don't think we have any blue cards. Do you have any up, Nick? No. So, just if you're going to -- if you plan on speaking or want to address in public comment, go ahead and fill out a blue card.

MR. FUGATE: So, one of the ways we've done this in the past is we have paused after each IOU planning area and asked the utility, invited the utilities to make any comments. So, if you're amenable to that, we'll do the same thing.

COMMISSIONER MCALLISTER: Absolutely. And if that's going to happen systematically, then they don't need to fill out blue cards.

MR. GARCIA: All right. Chris was pointing out that the Forecasting Unit is not as friendly as the rest of our division, apparently. No thank you's.

COMMISSIONER MCALLISTER: Yeah, I think it's just sort of a, you know, socially, well-adjusted, I guess.

MR. GARCIA: You can say social awkward. They get too many numbers. They don't talk to human beings.

(Laughter)

MR. GARCIA: All right. So, I'm going to start with the folks that traveled the furthest, over 500 miles, which I think is San Diego. So, initially, I had Edison here, so I'm going to skip to San Diego. I'm trying to be aware of like traveling plans and things like that. And then, I'll still go to PG&E after that, because they traveled as well, and they're here, in person.

So, real briefly, this is an overview of the San Diego forecast, a rough overview of mainly the inputs. So, this table here is the main economic drivers that I showed for the statewide forecast, just broken out for San Diego's planning territory, which is primarily the County of San Diego, with portions of Orange County, the way we've mapped it out. Essentially, their service territory.

And so, you can see the population in households, using the same projections that I mentioned this morning, but there's a slight decline, once again, in personal income. And the manufacturing sector, as I pointed out as well, has also declined and a slight decrease in commercial employment.

Though, obviously, we know we're kind of like at maximum employment. So, what that means these days is a little different.

But, anyway, so, ultimately and the forecast shakes out to having residential and commercial sector growth being, as Chris mentioned, those standard savings do have an impact there in the forecast, particularly in 2029 when they're maximized.

And then, we also have around 300,000 electric vehicles in there, totaling around 1,300 gigawatts of load in 2030. Specifically, for light duty vehicles.

And I should also mention, I may have glossed over it earlier, but Mark reminded me that we also include those medium and heavy duty projections, that the Transportation Unit prepared for us, into the forecast and that will get lumped into the commercial sector overall forecast.

And then, lastly, on this slide, I just point out the PV capacity that Sudhakar pointed out, so you know what we're working with when we're doing this comparison. So, around 2,300 megawatts of PV capacity for 2030. And all these comparisons are going to be for our mid case. I won't go into the high and the low cases very much, except for this very next graph, where I describe them.

So, here we can see, ultimately, the forecasts are not too different. You can see that adjustment downwards, with that weather adjustment that was more prominent for San Diego, as well as those standards kicking in, in 2019, kind of making that hockey stick down there at the bottom.

But, ultimately, the growth rate's about the same, 1.4 percent versus 1.5, as you can see. And, once again, the electric vehicles are -- do have an impact and increase that consumption a little bit there at the tail end relative to the starting point.

And in this consumption forecast, the industrial sector definitely is bringing things down a tad, too.

So, all those pieces playing out there results in this slightly lower growth in consumption.

So, moving from consumption to sales, this is the -- what I was trying to characterize earlier today, just in a graphical form. So, at the top there, you have our mid consumption forecast that was on the previous graph. And the difference between these two lines, the green line being the sales, is essentially the self-generation. You can see the numbers that I pull out there, so all looking at 2030. So, around 4,800 gigawatt hours of self-generation impacts, those energy impacts. Eight-five percent of that is going to be PV and that capacity that I pointed out earlier.

And as Sudhakar pointed out this morning -- or, this afternoon, actually, those commercial PV installations are going fast than residential. And you can see that effect at the tail end of the sales. You can see that flattening out in comparison to consumption forecast that is going pretty straight out to 2030.

And, ultimately, the additional PV is going to bring down that sales number, but slight changes in comparison to the previous forecast, in the mid case.

And so, we have had discussions with the forecasters at San Diego Gas & Electric. So, comparable EV and PEV impacts, looking at their submitted forecast, essentially, just brought back in their efficiency estimates to kind of create a baseline that we can compare against our forecast. And so, ultimately, that unmanaged forecast grows slightly faster than our CEC baseline. But the unmanaged peak is growing very similar to the CEC, but the 2030 estimate is higher due to some differences in starting points, as well. But I think we're on the same page.

We do want to talk a little bit about -- well, going back to the EVs, it's definitely comparable in the short term, but there's some long term differences we discovered in that, and we want to dig into that, particularly with our Transportation Unit a little bit more.

And we did find some differences in our commercial floor space projections, so that kind of bumped up our commercial sales forecast in comparison to what San Diego was presenting. So, we're going to discuss that a little bit more, as well, and put San Diego in touch with our commercial floor space modeler.

But at this point, I just want to invite San Diego up to provide any comments, if they would like.

The moment of pause.

MR. SCHIERMEYER: Thanks, Cary. First of all, I'd like to thank the CEC and the staff for all the hard work in putting together this preliminary forecast. And then, also, having calls with us to compare our submitted forecast, and then providing additional information. It was very helpful.

In reviewing --

COMMISSIONER MCALLISTER: Could you just state our name and --

MR. SCHIERMEYER: Oh, I'm sorry.

MR. FUGATE: Just for the record, the court reporter needs to know.

MR. SCHIERMEYER: Yeah, my name is Ken Schiermeyer, and San Diego Gas and Electric. And in reviewing the baseline forecasts, we agree the sales look comparable in the beginning, and then they kind of -- they differ in the end and we'd like to continue to, you know, look into that with the CEC staff.

We'd also like to look at the baseline forecasts with the new committed energy efficiency separated out. That might help us with the comparison. And so, I've asked Cary for that and he's graciously accepted to do that.

We look forward to including the AAEE, when that is available, you know, to compare the fully managed forecast at that time.

And then, I think we'll reserve any other comments after we've circulated information within our company.

COMMISSIONER MCALLISTER: Great.

MR. GARCIA: Cool, thank you. Thank you, Ken.

So, I'm going to move on to Pacific Gas & Electric. A similar summary. As you can see here things are, in comparison to the other planning areas -- or, I guess, in comparison primarily to San Diego, the IOU territories, PG&E's territory is split up into seven -- or, sorry, six climate zones. And so, that's going to be spread across all the way up to the North Coast, down to portions of the Central Valley. The Sacramento region down to Fresno/Bakersfield. Those are two separate forecasting zones. We have a Central Coast Zone, as well as a North Zone, a little further up in the valley.

And so, we'll also provide these breakouts. We're going to post the forecasting zone results, as well, so you can see these comparisons. We weren't able to do those in time for this workshop. They'll be able to shed some light on what I'm discussing here.

So, similar story across the State. So, you can see personal incomes going up a little bit here and that's probably going to be driven by the Bay Area, where you see those income growth being pretty high. And that would be our forecasting zone, suitably titled The Greater Bay Area, for PG&E. So, that's going to be the City and County of San Francisco, and the surrounding Bay Area counties.

In our forecast, it's currently around 1.6 million EVs by 2030. And you can see the break out of that electricity impact there in the capacity of PEV by 2030, around 10,600 megawatts in our mid case.

So, moving on into the consumption, it's pretty clear there's basically the same growth rates. There's going to be a little dip there. As we've mentioned a few times today, those standards are kicking in, in 2019, and then particularly for PG&E, we use those first three years of rain data in the AG model, so that's going to bring things down a little bit because you're not having as much electricity usage for irrigation pumping, as you would expect if you have more precipitation.

As I mentioned, the Greater Bay Area is definitely leading this planning area. So, consumption's at one and a half percent per year, from 2019 to 2030. The same story with industrial mining, that consumption is definitely down and declining across the planning area, if you look at it on a forecasting zone level.

But the Central Valley is still growing pretty strong. And we all know it's going to have more houses, large population growth there. And so, that's continuing to increase commercial demand and the residential demand in those particular forecasting zones. And those would be this Sacramento region, as well as the Fresno to Bakersfield regions.

Moving on to sales, you can see in this case, with a little bit more PV that's going to bring down the sales forecast, considering that the consumption forecast is about the same. But, yet, the PV increased a little bit here.

And, so, 96,600 gigawatt hours of sales. You can see the self-generation numbers right there, 72 percent of which is going to be from PV. And another interesting note about the Central Valley, so that accounts for about -- once again, this is in 2030. So, in our 2030 forecast, it accounts for about 50 percent of PV generation in the PG&E planning area. But at the same time, their per capita electricity sales are also much higher than the rest of the planning areas. And that's something I think we've sort of already known.

There's obviously some, many disadvantaged communities in the Central Valley and we generally know there's a lot of -- I mean, it's generally hotter during the year, larger homes, potentially, in comparison to more urban areas in the Bay Area, for example.

And here's where I touch on the comparisons we've had. Similar to San Diego, we had discussions with Pacific Gas & Electric. The quick comparison is, really, PG&E has a higher EV forecast than we do, but a slightly lower PV forecast. And so, there were some differences in the modeling approach for EV that we want to discuss a little bit more. And there's going to be a difference in the capacity factors applied to the PV forecast as far as the generation. So, we want to discuss that as much as we can to make sure we're on the same page there, and address any issues we may find between our two forecasts.

And so, but ultimately accounting for these differences, the sales forecast is comparable to the CEC. Although, there's some slower near term growth, but faster growth in the long term. A little faster growth in residential and agricultural sectors in comparison to our forecasts.

And then, there's slower growth in commercial and industrial sectors. And similar to San Diego, I haven't looked in detail. The issue with the commercial floor space primarily came up with discussions with San Diego, but we may take a second look at our commercial floor space projections for PG&E, as well, just to confirm that it's an isolated issue for San Diego, specifically.

And then, ultimately, looking at the peak demand forecast there at the bottom, we do have some differences. PG&E's forecast is generally very flat and then declining in the long term, where as our forecast shows a little bit of growth, particularly a little bit more in the long term, than PG&E's forecast.

But we've had those discussions and we're working on finding ways to address that, address those differences. At least to understand why those differences exist and see if there's any changes we need to make in our forecasting methodology there.

But at this time, if there's anybody from PG&E who would like to comment.

MR. KOLNOWSKI: Good afternoon, Ben Kolnowski, PG&E. I'd like to start off by saying thank you to the CEC for the work and effort they put in to developing the forecast, and especially the collaborative approach that they've taken to share the results with us, and discuss the results.

I have a couple comments. First is on the peak demand forecast. I think Cary touched on some of the differences there. We have a relatively flat forecast, while the CEC's is slightly increasing. And I'd like to dive deeper into what assumptions will come into play once AAEE and storage are included in that forecast, because I would imagine that would dampen that growth a little bit and maybe bring us more in line.

And then, in terms of the sales forecast, I think he correctly characterized that our EV forecast is higher and the PEV forecast is lower for PG&E compared to the CEC. And we'd like to dive into that further, to explore those differences.

And the rest, we'll reserve some comments, as we discussed internally, and dive deeper into the issues, and submit some comments, written, by the timeline. Thank you.

MR. GARCIA: All right, I'm going to back up a little bit here and get back to Edison.

MR. FUGATE: I just want to make one point. So, I think we've covered all the planning areas for which we have utility representatives in the room. But if there are folks on the phone, who are anticipating making comments, please use the raise hand feature, on the WebEx, so that we know to unmute you.

MR. HERNANDEZ: Excuse me, I'm here representing Southern California.

MR. FUGATE: Oh, okay, I'm so sorry. Well, then, we should have -- okay, so, I guess that will apply for just L.A. and SMUD, unless I'm misspeaking again. Okay. So, when we move into L.A. and SMUD, if there's anyone on the phone who would like to make comments, use the raise hand features, please.

COMMISSIONER MCALLISTER: Okay, great.

MR. FUGATE: Okay.

MR. GARCIA: All right, we missed you. We apologize for that.

All right, so, we have the similar summary. Once again, population, households, slight decrease here in the personal income in comparison to the last forecast, and manufacturing output, once again, is down a little bit. And commercial employment stays about the same.

So, a similar to story to PG&E, actually. So, we see that population growth and the household growth is going to be higher in those inland areas. And that's primarily because it's just easier to build.

Like, for example, a portion of Edison's forecasting zone is going to be Riverside County. And so, it's just going to be easier to build there. Once again, larger houses, faster population growth in those particular areas.

1.1 million EVs and the 8,200 megawatts of PV capacity in our mid case for 2030.

So, looking at consumption, not much change in our two mid cases, that you can see there. Sitting, you know, pretty right in the middle of our high and our low cases here.

Residential and commercial sector is a little bit lower, but still growing at similar rates as our previous forecast. And then, that same story, once again the industrial mining sector, as I mentioned, you know, over the past decade or so that's been declining and that's continuing to see that.

Inland and household population growth, as I mentioned, is continuing. And so, Eastern and Big Creek West forecasting zones, that's where the residential sector seems to be growing the most.

Eastern, as I mentioned, is going to be that Riverside County portion of Edison's planning area. Big Creek West is going to be Ventura and portions of Santa Barbara County.

And here's how everything shakes out as far as moving from consumption to sales forecast. In this case, a large portion of that self-generation is going to be PV. You can see that at 75 percent there.

And then, kind of doing that comparison by the forecasting zones, we see more PV impacts becoming higher in the inland regions. Although, the actual growth in PV capacity is still a little slower, on average, in comparison to like L.A. Metro, for example, which is going to be just right in the center of L.A., in Edison's planning area.

Sales forecast here that we're looking at, in this comparison, so a fairly higher EV assumptions according to Edison's forecast. But the PEV impacts seem comparable there. Our capacity's about the same, maybe a little -- some small differences. But we're, by and large, pretty close together on that one.

Edison does show some declining sales forecasts for their bundled customers, and a big portion of that is load migration from Edison's bundled, to like CCAs, for example L.A. County, being the largest CCA down there at this point.

There are some differences in peak demand that Chris pointed out today, in the previous presentation, looking at those load shapes and issues around peak shift. So, we'll have to dig into that a little bit more, for sure, but we have discussed that with Edison, through our DAWG, and through separate meetings with their forecasting staff. And we seem to be on the same page, we just need to work out these differences in our forecast to get into the nuts and bolts of what are assumptions are here.

And then, lastly here, you can see the peak demand in their forecast is declining over the 10-year period, whereas ours is slightly growing.

So, at this time I would invite you up to comment for Edison.

COMMISSIONER MCALLISTER: That's for your patience there. It was totally unintentional. So, thanks for coming up in person.

MR. HERNANDEZ: Hello. Thank you, everyone. My name's Sean Hernandez, representing Southern California Edison. I'd like to thank the Commission for this great work. It's a lot of work, a lot of numbers, and I know everybody worked really hard on it and gave a lot of considerations. Racked their brains, probably really hard, thinking does this affect that, and does that also affect this. So, thank you, everybody, I know it's not easy.

So, I first wanted to comment that I did expect to see a little bit more about natural gas demand in today's presentations. I probably would have a few follow-up questions for some of the staff members. And also, Angela Tangetti and Anthony Davies regarding the natural gas modeling.

My understanding is that there's an electric sector optimization model that's used to calculate the natural gas demand and I'm unclear at this time if that work's been completed, yet. And I'd like to learn a little bit more before we file our comments.

I'd also like to understand if that resulted in a preliminary electricity price forecast, because the natural gas demand forecast also leads to electricity prices. So, that's very important, also, for the PV forecast, for the TE forecast, as we all know.

Third, I'd like to mention some energy efficiency food for thought. I'd like to encourage the Commission to consider just a question, really, I don't have any answers here, but does the new framework of the Integrated Resources Planning proceeding call for deciding EE portfolios in a new way?

In that proceeding, there is extensive conversation about selectable versus non-selectable EE, but so far, based on the fact the proceeding's using the IEPR forecasts, it's remained only as a load modifier.

So, I would like to ask staff and the Commission to consider what would be appropriate for increasing that engagement between these two proceedings.

So, what would be selected if we did take an approach like that and what role would the CEC like to play in such an evolution, if it decided to?

Last issue, regarding Mr. Konala's presentation on self-generation, I just wanted to flag the feature of flat CHP forecast. In the previous IRP, that did create a little bit of a controversy and a little bit of modeling headache. It may not be reasonable to assume that industrial CHP and electric sector CPH is remaining flat, at a minimum, because the carbon allowance price for Cap and Trade will be increasing, so there will be an economic incentive for some of those units to be taken offline.

And what the CPUC ended up doing is assigning those CHP emissions to the electric sector, so that basically crowded out what would have otherwise been electric sector natural gas generation during ramping and nighttime hours. And it's possible that that could have reduced total system costs in IRP modeling.

So, we may need a forecast for CHP because it does seem reasonable for it to be declining, instead of flat. But happy to discuss these issues in an ongoing manner with staff, and the Commission. Thank you for your time.

COMMISSIONER MCALLISTER: Hey, thanks for being here. Just a couple comments and maybe, Cary, you can talk about the production cost modeling, the status of the production cost modeling.

But to your point about sort of what happens in an IRP procurement kind of scenario is right on. And, you know, I don't think anybody really has the full answer to that. But we are talking a lot with the PUC about this. And, in particular, in the context of the Energy Efficiency Action Plan that we're updating right now, that will be sort of hitting the airwaves in the next week or two. And we have a workshop, I think it's on the 27th, about that.

So, that's a topic that we ought to air out there. We ought to begin to think about how efficiency can, you know, evolve to play alongside all these other resources we're talking about, and alongside demand flexibility, you know, more broadly, right.

So, I think all these topics are really in the air and it's great if Edison can participate and sort of bring that creativity, and all of us can sort of put our thinking caps on. Because how -- you know, and the rate regime going forward is really an integral part of this. So, you know, everything's kind of related at this point.

So, anyway, I really appreciate your comments and expressing those thoughts. And then, you know, hope to keep engaging on that really deeply. So, thanks.

MR. GARCIA: Yeah, and as far as the production cost modeling, so these preliminary results will feed into their work over there, the modeling, and then it kind of iterates back.

If you remember the presentation I gave earlier in the year, it's sort of an iterative process. So, this preliminary will feed into that, and then those numbers, from NAMGAS, for example, give us some gas rates. That will feed back into our models and then we'll get the whole process once again.

MR. HERNANDEZ: Thanks, Cary.

MR. GARCIA: Then, once we get this done, we'll --

MR. H ERNANDEZ: So, if I hear you correctly, we have completed the electricity demand forecast, which is going to go into that PCM I described, and then we're going to get the natural gas demand forecast.

MR. GARCIA: Correct.

MR. HERNANDEZ: Terrific. Thank you, everybody.

MR. GARCIA: Okay, I'm jumping around here. All right, we're going to go to SMUD, because that's the next one I landed on.

So, as we talked about earlier and Sudhakar was, in fact, right, the population growth in the Sacramento Region is definitely higher than other parts of the State. But the population households are locked in at the same rate, roughly, as you can see in this table here.

Personal income, once again down a little bit there. Manufacturing output, as well. And then, commercial employment stays about the same, although there might be a slight adjustment downward there, actually, because these are rounded up. So, there might be some small changes.

Ultimately, there's slower growth in residential. And it's a relatively small sector, as you saw on the statewide level, but there was some interesting information from the TCU sector. But, ultimately, that slowed down in growth as well. And, once again, that's going to be your transportation, communications, and utility sector.

A hundred and twenty thousand EVs are assumed by 2030 and then, roughly, 660 megawatts of PV, as Sudhakar pointed out earlier today.

Consumption is about the same, you know, only a minor difference in the overall growth here. But those new building standards do apply, as well, for SMUD. So, that drops things down a little bit in 2019, in comparison to the previous forecast.

And that little bit about TCU that I pointed out, that was just me investigating probably a little more than I needed to. But it was an interesting little tidbit of information, just on the historical trends and the telecommunications. So, what's happening in SMUD, in particular, for the TCU unit, is there's the transition from wired components to wireless. And so, that employment and the work done in that sector has dropped off, and the wireless technology is picking up. So, that's just a little snippet of information.

And you can see this at a national level, where things have sort of -- employment has been declining in wired telecommunications technologies, and it's started increasing in the wireless sector.

If you ever want to dig into NAICS Codes, it's interesting stuff to get in there and to see this in more detail, if you have a lot of free time on your hands.

Moving from consumption to sales, you can see here the impact of that PV generation. SMUD is a little different where around 96 percent of the self-gen is coming from PV, so that's a pretty large proportion. And I think that's much higher than most other planning areas in our State.

And I should also mention that SMUD is actually not a planning area unto itself. It's a part of our Northern California non-CAISO planning area that's broken up into three forecasting zones. So, SMUD is one of the three. Turlock, Modesto, and other portions of the Balancing Authority of Northern California are going to be the other two forecasting zones within that.

And then, back to here, though, so this PV growth that we're seeing here just definitely results in slower growth and sales in comparison to what we saw on the consumption forecast on the slide previous.

So, I didn't talk about peak demand for the IOUs, because we addressed that in the hourly model. We haven't, yet, gotten to modeling peak demand for the other planning areas that are at an hourly level, so we use load factors that we have developed from our previous HELM model to derive peak demand from the consumption demand fed into it.

So, ultimately, as you saw on the previous, you're going to see numbers very similar to consumption because that's essentially what peak end use load is. That's like going to be your demand, irrelevant of generation source, just your raw demand for end use.

So, a modest decline here in peak end use load. And that's going to be driven, as I said -- your peak end use load is going to be driven by your weather-sensitive sector, so residential and commercial. So, if there's a decline in your commercial sector consumption, you would expect a similar decline in overall peak end use load at the end of the day.

This is a little, slightly more complicated graph, but this is going from gross generation to net peak, and then also to peak end use load. So, as I mentioned, you can see peak end use load down there at the bottom in the green line.

The difference between that and gross generation is your losses, so you do that calculation of losses there. And then, the difference between the gross generation and your net peak demand is going to be that self-generation impact.

So, ultimately, this is going to basically grow out your sales rate, because it's essentially what it is just on the peak side, when you think about it. And so, 1 percent in compared to 1.3 percent, slight decline there. You're going to have more PV having an impact, obviously, as well as the impacts that are happening on the underlying sales forecast that's going to feed into the peak demand forecast. So, as outlined here.

So, you see this -- I pointed out, at the bottom there, you have this increasing self-generation impact that results in that decline in your net peak, relative to end use load. So, you see our end use load slowly -- your end use load, I guess, graph, and your net peak graph slowly kind of reaching point as that self-generation begins to increase at such a rate.

So, quick comparisons to SMUD's forecasts. So, overall, it includes less PV and less EVs. But, ultimately, we end up being on the same page there, at the end of the day, in comparison to our forecasts.

We have some declining residential sales growth in their forecast, but some large growth -- or, actually, some growth in their large commercial customer demand. SMUD breaks out their forecast into more disaggregate customer classes, in comparison with us, so that's what's going on there.

Ultimately, their sales forecast is pretty flat over the 10-year period, and that's looking at -- that's actually including sort of a managed forecast to include energy efficiency over their demand forecasts, as some of the other utilities that submit data to us, do.

But, ultimately, our forecast is showing a higher residential and commercial demand. But when you do that comparison to an unmanaged forecast, and you basically bad -- we seem to add back the energy efficiency savings to create an unmanaged for SMUD, and we end up being pretty close to the same as far as sales.

We do have similar growth expectations for peak demand, when looking at like an unmanaged version of SMUD's forecast. But their managed forecast shows a decline over the long term period here.

And I don't believe we have anybody on the line from SMUD, but if we do, I'll leave it there for comment.

Okay, just a last note as far as the sales. So, as I said, we're pretty close. And as I mentioned, SMUD has less PV and less EVs. But on our end, we have more PV and more EV, so it ends up being a wash as far as our assumptions. We're not too far off, but we want to dig into that and understand what's going on there. But SMUD has pretty good on-the-ground information and they're pretty involved in their EV programs.

COMMISSIONER MCALLISTER: Yeah, I would say they're going to have really good information about --

MR. GARCIA: Yeah.

COMMISSIONER MCALLISTER: -- like they have a very well-developed electrification program and, I mean, I think they'll be able to help us anticipate pretty well what's going to happen here.

I mean, one question I kind of have throughout this is in the out years, you know, the interplay between all these different wedges, and demand modifiers, and everything, how much does some of the uncertainty in each of those individual areas kind of compound?

MR. GARCIA: I think it definitely does compound, for sure.

COMMISSIONER MCALLISTER: Yeah, so like how much -- what are the air bars around this stuff? Are they getting wider over time and how can we deal with that, or do we need to deal with that, I guess?

Anyway, but probably we can talk about that offline. But, you know, I think there's -- there are more sources of uncertainty --

MR. GARCIA: Yeah.

COMMISSIONER MCALLISTER: -- as we -- you know, each new forecast and so, you know, how do we sort of bound that?

MR. GARCIA: Well, yeah, so --

COMMISSIONER MCALLISTER: Yeah, I've talked about this before with Chris a little bit but --

MR. GARCIA: Right. And so, well, just thinking about what you had said about the -- and you can see this comparison, as I mentioned before, like in our short term we're all pretty close, we're not too far off there. But as we start getting, you know, into that 5-year period and beyond, that's when I start -- we start seeing, just looking at our forecast in comparison to the utilities' forecasts, we're definitely making some different assumptions about what's happening in the long term.

EVs, for example, in some of the utility forecasts you see almost like Bass diffusion kind of situation happening, where it may not be paying, perhaps, not as much attention to policy impacts and influence, as it may, but that's something that's hard to put a confidence interval on, right. Like, what happens with a certain, a new policy that may take place that we weren't expecting? How do you model that out ten years out from now.

COMMISSIONER MCALLISTER: Yeah. I mean, that's going to require some interaction, not only with the utilities, and certainly first with utilities, but also with the ISO and the PUC. I mean, particularly the ISO like -- I mean, well, all the agencies have to plan out a decade, right? I mean, it takes -- these infrastructure projects and these investment plans, they have to contemplate, you know, definitely more than a few years out. So, we need to work pretty hard to develop a comfort level with those sort of medium out years, so that we can be on the same page with the forecast.

MR. GARCIA: Do you have any comments?

COMMISSIONER MCALLISTER: I don't really see any nodding heads in the audience, maybe one or two, but anyway.

I mean, the last thing we want to do is, you know, take the forecast to the agencies and say, okay, well, do you see any problems with this and have them say, yeah, you know, we're not confident in your fifth year or your sixth year, you know.

MR. GARCIA: Right.

MR. FUGATE: I was just going to say that we don't see any raised hands on the WebEx, but we do have some call-in users. So, what we'll do at the end is just open up the lines in case there are any comments from anyone.

MR. KAVALEC: I just wanted to make one point about uncertainty. And as you mentioned, and we've talked about it in the past, this in the past. And, really, what it comes down to, our users typically want a point forecast. Maybe the way to think about incorporating uncertainty in the future is to urge our stakeholders, users of our forecasts, to start thinking about using distributions of results instead of a point forecast.

COMMISSIONER MCALLISTER: Yeah, thanks.

MR. GARCIA: Which portion of the distribution should we pick, though?

All right, last, but not least, LAWDP. So, when we talked about it earlier today, there's definitely some -- an issue around the household projections that we have for these climate zones. And so, L.A., as I mentioned, is split into two climate zones. There's an inland and a coastal. And so, we may want to actually combine those. We're not too sure if there's much value in having that before -- that's a carryover from how we had done this decades earlier.

And so, that may be somethings that needs to be addressed. It might help make it a little easier to develop these household projections for LAWDP.

But nonetheless, here's the table breaking out some of the projections. As with before, those population households are going to be the same as last year. Differences in personal income that you can see here, as well as the manufacturing output and then, once again, commercial employment is going to stay about the same.

And then, I think it's the story across the

State that declining industrial and mining sector really happening just about everywhere.

And then, you can see the EVs that we're assuming for LADWP at the bottom there, around 370,000 light duty electric vehicles by 2030.

Looking at consumption, you can see that drop there in comparison to the previous mid case, and this is going to be due to the residential and commercial consumption being slowed down due to those economic drivers that I mentioned. So, personal income coming down, low growth in households, as well as the standards that we mentioned before.

Then, once again, industrial sector here is declining much faster than 2018.

This is the sales forecast. You can see the comparison at the top there. And as we noted before, there's -- just looking at the numbers here, there's much less self-generation in our forecast in comparison to other parts of the State. So, we'll address that, as I mentioned, through looking at the household numbers. So, we can dial in those household additions and that will increase the potential of roof space for the PV adoption. So, we can fix that and look into that a little further, and that might change these numbers for the revised forecast, as they come up.

And, ultimately, this shakes out to having PV capacity growing a little slower than the statewide average.

Peak end use load, here it's much lower. Those weather-sensitive sectors are really going to drive the peak end use load, as I mentioned, for SMUD. And so, if you have a lower residential and commercial sector consumption, that's ultimately going to lead to lower peak end use load growth.

And you can see the differences there, 1.2 percent versus .6 percent that we have now. So, it's a little bit slower growth. But, yeah -- yeah, much lower low case as you can see, pretty obviously. And the high case is a pretty tight balance from those two numbers.

Moving from peak end use load to the net peak, you can see the self-generation impact. Only about 280 megawatts of peak -- of PV at that peak there. So, once again, that slower peak end use load growth is going to result in a similar slow down in the net peak forecast. In this case a little bit more significant, 0.4 percent versus 1 percent here.

So, LADWP's forecast for sure includes more EVs and PEVs -- PV, and as well as EVs. As I said, there is lower residential and commercial sales forecasts. That's going to lead to an overall lower forecast in comparison to the CEC. Aside from those sales differences, the peak forecast is pretty comparable. We're definitely, also going to see that the peak forecast that we're using actually has a lower starting point in comparison to what they have. So, we want to take a look at that a little further. And we're reached out to LADWP staff to set up a call at some point, shortly after this workshop.

I mentioned before looking at LAWDP housing. We want to dig into that a little bit further and see what's going on in those projections.

There is a significant reduction in there, as I said here, in their residential and commercial sales, but they also have a higher peak demand forecast, which has me scratching my head a little bit. I don't quite understand how the overall sales could be declining, but yet, you have a much higher peak demand forecast than we have, when we have these differences in both our forecast. So, this could be driven by differences in PV and EV. And I noticed it more in their commercial sector. There's quite a bit of a decline downward that seems a little peculiar, and then it starts dipping up. So, it's sort of like a little Nike swoosh, for example, happening in their forecast for commercial sector, specifically. So, we'd like to dig into that a little bit more and find out what's going on in there.

But I don't believe anybody on LADWP's on the line. But I think at this point, we'll just opening it up, if there's any additional public comments before we go.

MR. FUGATE: So, actually, we do see at least one LADWP representative. Is his line unmuted?

MS. ZHANG: This is Bingbing Zhang from LADWP. Can you hear me?

MR. FUGATE: Oh, yes, we can hear you.

MS. ZHANG: Oh, okay. Yeah, thank you for everybody putting into all the effort put into this detailed forecast. So, I heard all your questions and so, we'll be happy -- I will be happy to assist you guys with all the questions and so we can learn more from the forecast. And, also, I will be interested in, you know, getting more details on the hourly forecast and also the peak hour shifting, if you guys have any additional, you know, input, so we can improve our forecast as well.

MR. FUGATE: Okay. Thank you, Bingbing. Currently we do not hourly forecast the LAWDP, but that's something that we can talk about the future for sure, and we'll definitely reach out to you guys soon. I think I reached out to the colleague who submitted your IEPR demand form. So, I'll make sure to include you in that communication, as well, as we can follow up.

MS. ZHANG: Yes. They are the coordinated our LAWDP communicating with CEC. So, yes, I will make sure that they will, you know, include us in this discussion.

And another quick answer to one of the questions you had, how come our peak demand goes higher, while our consumption forecast goes lower? Was that one of your questions?

MR. GARCIA: Yes.

MS. ZHANG: So, the way basically was not using the same load factor to forecast for the future. We forecast our load factor, as well. So, in the past several years, the load factor has been dropping down. That's probably one of the reasons causing the increase of peak demand, however the consumption has been lower.

MR. GARCIA: Okay, thank you. Yeah, we'll definitely follow up with you, Bingbing and have a more -- a deeper discussion on that. That would be great.

MS. ZHANG: Okay. All right, yeah, I'm looking forward. Thank you.

COMMISSIONER MCALLISTER: Did we open all the lines? Okay, so I think we should be good.

MR. FUGATE: Okay.

COMMISSIONER MCALLISTER: Any wrapping up comments, deadlines, housekeeping stuff?

MR. FUGATE: Yes, so I believe the comments for this workshop are due on August 29th. That's in two weeks.

COMMISSIONER MCALLISTER: Great.

MR. FUGATE: So, I want to thank everyone for coming.

COMMISSIONER MCALLISTER: Yeah, I guess I want to thank Cary for the presentation and all of you for sticking it out to the last. It's a little sparse, you've got the diehards here in the room.

But, you know, this is not the most accessible conversation, but it is absolutely one of the most important conversations we have at the Energy Commission. And it ends up with a really robust platform for having discussions about how we do our energy planning going forward.

And as we transition to, in many ways, actually, our energy sector an as we sort of morph between gas and electricity, and we try to figure out about demand flexibility, and disaggregation, and locational, temporal, all of the different trends that we're seeing across the State, it all kind of comes home to roost right here. And so, this conversation is really critical and we have to produce a good product so we can have, basically, a consensus across the State that it's going to be used going forward. And this is the common language we're going to use.

And so, anyway, I want to just thank everyone for your participation. And, certainly, thank staff in the Demand Analysis Office, and just everybody in the Assessments Division, and the other divisions who contribute to getting this train rolling down the track. And we have a few stops to make along the way, but we'll get to our destination here before January, by January of next year. So, thanks again.

Anything else? All right, thanks, everybody for coming. We're adjourned.

(Off

(Thereupon, the Workshop was adjourned at 4:03 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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