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CALIFORNIA ENERGY COMMISSION

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2025 Integrated Energy Policy Report (2025 IEPR)	)	Docket No. 25-IEPR-03
RE: Electricity and Gas Demand Forecast	)	

IEPR COMMISSIONER WORKSHOP ON

LOAD MODIFIER ENERGY DEMAND FORECAST RESULTS

REMOTE ACCESS ONLY VIA ZOOM

THURSDAY, NOVEMBER 13, 2025

10:00 A.M.

Reported by:

Elise Hicks

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P R O C E D I N G S

10:01 a.m.

THURSDAY, NOVEMBER 13, 2025

MS. RAITT: All right, well, good morning, everyone. We'll get going here. Thanks for joining today's Integrated Energy Policy Report, or the IEPR Report, pardon me, Commissioner Workshop on Load Modifier Scenario Energy Demand Workshop -- Demand Forecast Results. Excuse me. I'm Heather Raitt, the Acting Director for the IEPR Team here at the CEC.

This workshop is being held as part of the CEC's proceeding on the 2025 IEPR. Today, we're doing a remote workshop using Zoom. This workshop is being recorded. The recording will be linked to the CEC's website shortly after the workshop. To follow along, the schedule and slide deck have been docketed and are posted on the CEC's website.

There will be opportunities to ask the presenters questions. We'll have a few minutes after the panels to take audience questions, but we may not have time to answer all questions submitted.

The Q&A feature is available for you to submit questions. Just type them in. You can also upvote a question by clicking on the thumbs up icon. Questions that receive the most upvotes are moved to the top of the queue.

Attendees can also make comments at the public comment portion of the workshop at the end of the day. Please note that we will not be able to respond to comments today and comments are limited to a maximum of three minutes per person with one person per organization.

Written comments are also welcome and instructions on how to provide those can be found in the workshop notice and written comments are due by 5:00 p.m. on November 26th.

And with that, I'll turn it over to Commissioner McAllister to start the day. Thank you.

COMMISSIONER MCALLISTER: Great. Thanks Heather. I really appreciate you and the rest of the staff, the IEPR Team for putting this together. I've been really looking forward to this. You know, the forecast itself is a super important kind of foundational resource for the state. And the load-based, the sort of load modifiers, you know, are really, I think, an area of high-level innovation and market dynamics that we need to understand, and that can also really be a force for good. We have a lot of challenges which I'll comment on in a second, but just in terms of, you know, nobody has a crystal ball and so we do our best to create that crystal ball and the forecasting process in this workshop is part of that.

But all of this happens in close coordination with our colleagues at the Public Utilities Commission.

And I want to welcome Commissioners Douglas and Houck, and I think we may be expecting Commissioner Baker at some point during the course of the day.

Vice Chair Gunda, who would normally lead this, is out for a speaking engagement. He'll be back sort of late morning or in the afternoon. We do have Raja Ramesh from his office to make some comments here in a second as well.

I wanted to just, you know, point out that we live in very interesting times. And those of us who are intellectually curious, I think it's a great time to be alive. And just the staff resources, the modeling expertise, the data collection that we do, the stakeholder engagement as part of the forecasting process is invaluable and a huge team effort, multi-agency effort. The Demand Assessment Working Group, the DAWG, you know, is also a sort of senior staff and interagency working group to help vet some of the issues that we'll hear about today and sort of, you know, put them through their paces and develop them in a way that's ready for primetime. And that's also together with the Independent System Operator, so senior staff CAISO and Cal ISO, and then also with the Air Resources Board on a number of the issues involved there too.

So really, you know, there are four sort of energy agencies constantly working together but a lot of the policy and decision making sort of originates with the forecast as a platform. And so, you know, the IRP process and RA process over at the PUC and the transmission planning efforts over at the Cal ISO really do leverage the forecast, really utilize the forecast in a very organic way as the base for those conversations.

And so it's a big team effort and I think we're lucky to be able to do this in California and have the resources to be able to have this very rich discussion really every year now, you know, not so much every other year but really every year.

But the odd years like 2025, you know, roughly full forecast I think, you know, adjusting with the needs of the day to focus on the top issues. And load modifiers, you know, transportation electrification, building electrification, all the load growth that we're facing, rooftop solar, behind-the-meter battery storage, you know, the fuel substitution work that we'll hear about is really key, so moving from gas to electricity doing that load growth and understanding it and trying to predict where it's going but also informing policies to help it move in a way that's beneficial to the grid and optimizes the resource that is the grid that we've already built and manage investments going forward.

I think all of these questions are in the mix here as we look about, okay, what do we know about load modifiers which we'll talk about today. You know, electrification generally is our backbone, our path towards decarbonization, and I think we all understand that it's a huge opportunity. It presents challenges. Load growth presents challenges to different -- different than the past few decades but it also represents a great opportunity to incorporate load in a way that that manages rates and provide some downward pressure on energy cost.

I guess the last thing I'll say is just, you know, load flexibility, we'll talk about that some today, but load flexibility is really emerging as a tool that has huge potential to optimize the use of the distribution grid particularly but, you know, the load, that 7,000 megawatt load flex goal that we have is sort of, you know, half supply side sort of, you know, peak shaving and the other half is load modifying sort of, you know, lifting the other hours the non-peak hours in terms of incorporating the new load into those hours so that we don't drive too many hard costs into the grid.

Load flexibility is emerging as a complement to energy efficiency, which is a policy of the state, as a way for the demand side, for the new electrification loads to help us achieve our, certainly, our decarbonization goals, but also, you know, very importantly manage costs along the way and even enhance reliability so really that trifecta.

Anyway, so we've got a great agenda, a bunch of staff, I mean a dozen staff with incredibly deep expertise from the Energy Commission, certainly, to present and really looking forward to a robust discussion about each of the topics. At the end we'll talk about load flex a little bit and the Additional Achievable Energy Efficiency in the afternoon and fuel substitution draft results, and then talk about data centers, which is also a big driver. But really looking forward to the morning, distributed generation forecast and Transportation Forecast, and then the known loads, the larger loads, which will be, I think, a really interesting discussion.

So with that I wanted to hand the mic to Raja just to give a few opening comments on behalf of Vice Chair Gunda. And then we'll invite our colleagues at the Public Utilities Commission to provide some opening comments.

So Raja, off to you.

MR. RAMESH: Thanks Commissioner McAllister. My name is Raja. I'm a Senior Advisor to Vice Chair Gunda. He had a speaking engagement this morning, as Commissioner mentioned, and will join shortly. So he asked me to share these remarks on his behalf.

"This workshop is a critical part of our effort to develop California’s electricity Demand Forecast and planning today is more complex than ever. We have rapid increases in electricity demand from data centers, electrification, et cetera, shifting federal policies that add new uncertainty to the policy landscape, and there’s the growing difficulty of balancing reliability and affordability and getting the demand forecast just right is a critical part of that. It’s a difficult balancing act and we really appreciate the enormous effort our staff puts into refining these forecasts under such a challenging environment.

“Our collaboration with CAISO and CPUC continues to be vital and we especially want to thank our stakeholders, including the folks who participate in the Demand Analysis Working Group for your expertise and engagement.

“Thanks again for joining us at this workshop today. We look forward to a productive and thoughtful discussion.”

COMMISSIONER MCALLISTER: Thanks a lot, Raja. Looking forward to having the Vice Chair join us a bit later.

How about Commissioner Douglas, you want to join us for -- make some comments, and then we’ll pass to

Commissioner Houck.

COMMISSIONER DOUGLAS: Yeah, I'll just be very brief. Thank you very much, Commissioner McAllister. It's great to be here. I'm looking forward to the discussions and the presentation as always, and I'll pass it back to you.

COMMISSIONER MCALLISTER: Thanks Commissioner.

COMMISSIONER HOUCK: Commissioner Houck. Thank you Commissioner McAllister. I'm really pleased to be here today. I want to thank the Energy Commission for hosting this IEPR workshop. The issues we're going to talk about today on load modifier energy Demand Forecast results are really critical to the work we're doing at the PUC.

Work that I'm really focused on is, you know, how we're going to have the grid for the 21st century that's going to be able to address and make sure that we're successful in our clean energy transition. Grid planning is going to be -- is essential to this work. Also, we're looking at avoided cost calculator and data exchange to ensure that the right information is being shared to be able to make all of these systems work together.

Also decarbonization, building decarbonization, is also a critical area that I'm working on. And as Commissioner McAllister mentioned, load flexibility is going to be really, really critical to all of this which goes back to the grid planning. We need a grid that's going to be able to make all of that possible.

And I really want to thank the Energy Commission again for all of their work and analysis. It's absolutely critical to what we're doing. The collaboration we have across agencies with the CEC and the Cal ISO is also really critical. And I'm really pleased to be working with Commissioner McAllister, Vice Chair Gunda on all of this work and all of the folks at the CEC and all of your support that you're giving us and our agency and we're hoping that we're giving you that same support in the work you're doing.

So I'm really looking forward to hearing the information today and, again, just want to thank you for including us in the workshop.

COMMISSIONER MCALLISTER: We really appreciate you Commissioner Houck, as well, and thanks to you and all of your colleagues, and we hope to hear -- if Commissioner Baker's not with us yet, which I don't think he is, hopefully he'll be able to join us later.

But I just want to again highlight the collaboration with the PUC. I mean the cross-pollinization and just the discussions, whether it's, you know, on the rate making work that the PUC does and just the DER conversations, high penetration DER, and all these are very, very, you know, foundational conversations and rulemakings and decisions that the PUC is taking that govern the IOUs. And the collaboration that we have on sort of the data work and how we can leverage interval meter data and really inform our planning in a much richer way than historically has been possible, I'm super excited about all that.

And the forecast is certainly part of that. The load modifiers, you know, by their nature, they are diffuse and they are aggregated because that's what our energy system is for, is an aggregation. And so really just that, I think that context just can't be overstated, how this moment really has opportunity for us to move in these new directions in an informed way to help our ratepayers, but also really incorporate electrification, sort of embody that electrification pathway to decarbonization as a leader state. So I'm excited for this conversation.

And with that I'll stop taking up the airspace here and pass it to staff. I think, Heather, should we just pass it directly to Quentin?

MS. RAITT: Yeah, that would be great.

COMMISSIONER MCALLISTER: Okay, great. All right. So, first presentation by Quentin Gee from our staff here at the CEC to introduce the IEPR Forecast.

MR. GEE: Great. Thank you, Commissioner

McAllister. Thanks to the dais for those comments and welcome. Hi, everybody. My name is Quentin Gee. I'm the manager of one of the branches that manages the Energy Demand Forecast, Advanced Electrification Analysis branch. Our work really engages the load modifiers, but not all of them.

But today, we are going to talk about the load modifiers of transportation electrification; building electrification, or what we call fuel substitution; energy efficiency; behind-the-meter storage and solar; as well as some discussion on known loads.

So overall, I think, you know, we'll let sort of staff speak for or the results of the forecast sort of speak for themselves in large part. But I think it is worth sort of acknowledging first off that we are in a time right now of a large degree of uncertainty regarding, you know, what electricity demand is going to look like throughout the forecast period. As folks here I'm sure are aware, there have been significant changes in policy at the federal level and at the state level, and we'll talk some about those. And there's also just some broader economic uncertainty that has made it a little bit more difficult to pin down the forecast compared to previous years.

That being said, you know, we have opted to try to create a broader sort of characterization of how things could unfold, and this workshop is a good opportunity for us to sort of envision, you know, how that could all unfold and what it would look like overall.

So why don't I just go ahead and introduce the next speaker. That's going to be Mark Palmere from the Demand Analysis Branch.

Mark?

MR. PALMERE: Thank you, Quentin.

Good morning, colleagues, active participants, and members of the public, anyone else on the webinar. My name is Mark Palmere, and today I will present a brief summary of the 2025 Behind-the-meter Distributed Generation Draft Forecast results.

Slide.

To begin, here is a list of acronyms and initialisms I'll be using in today's presentation.

Slide.

Before looking at our updates, let's review the framing of this forecast. The technologies we forecast are solar PV, energy storage, and other generation such as fuel cell, gas turbine, and wind turbine. And the metrics we use to measure them are capacity and energy.

Slide.

Here is a look at the overall adoption modeling architecture, where you can see how historical adoption, compliance-based adoption, and economics-based adoption all lead into the overall adoption forecast.

Slide.

Why do we forecast distributed generation? Well, behind-the-meter, distributed generation technologies affect electricity demand served by utilities at both annual and hourly levels. And PV generation accounts for a significant share of overall statewide consumption, and that’s only increasing. This growth will help offset future electricity demand. And storage adoption affects peak demand by dispatching during peak demand periods, generally from 4:00 to 9:00 p.m.

Slide.

Drivers of the forecast include historical interconnection data and forecast factors that influence future adoption, such as payback period, which is mainly driven by technology costs, energy costs, export tariffs, and incentives, as well as Title 24 building standards, which mandate PV installation with all statewide new construction.

Slide.

And note that we conduct both economics-based and compliance-based adoption forecasting. The former considers the economic benefits of adopting solar, think retrofits, while the latter is used for Title 24 adoption.

Slide, please.

Now let's look at the inputs that have been updated for this year's forecast.

Slide.

There are several drivers of forecast uncertainty this year. The major change is that the Investment Tax Credit, or ITC, was eliminated in recent federal legislation, effective at the end of the year. On the other hand, tariffs are not currently included in the forecast due to significant uncertainty, and we continue to use NREL's Annual Technology Baseline to forecast future technology costs, the three scenarios of which are shown in the table to the right.

Slide.

With that in mind, we have developed four PV and storage adoption scenarios, first presented at our input and assumptions workshop this summer. Note the reinstitution of the ITC from 2030 to 2040 in our mid-plus-ITC case, as well as the storage retrofits via NEM contract turnovers in the high case.

Slide.

Another change this cycle is a higher new housing forecast. This directly affects PV additions through the Title 24 standards. Cumulatively, there are 420,000 more single-family home completions forecast between 2025 and

2040. We see a higher short-term housing forecast due to an increase in smaller household formations. Household additions do decrease in the longer term due to an aging population.

Slide.

We also updated our assumptions on the pairing of storage with Title 24 residential new construction. We previously assumed that builders would not add storage to new homes, as it wasn't required and would thus be an unnecessary cost to them. However, internal discussions have informed us that there actually is some storage paired with PV on new residential construction.

CEC's Building Standards Team has reported that their industry contacts indicate a storage attachment rate of about five percent. We applied this to the mid and low case, while our high case uses a higher, more optimistic number from an LBNL, Lawrence Berkeley National Laboratory, study, which is close to 17 percent. This means we're adding about 30 additional megawatts of storage to our low and mid cases per year due to this alone, and about 100 megawatts in the high case.

Slide.

Given all that, we are now ready to look at forecast results.

Slide.

First, looking at annual results, the PV additions are greatly affected by the elimination of the ITC, as we would expect. We see a 50 percent reduction in adoption in all cases starting in 2026. However, our special case reintroducing the ITC in 2030 through 2040 does lead to 2025 levels of added capacity in 2035. By the end of the forecast period, which is 2045, mid case additions are approximately 25 percent higher than in the low case.

Slide, please.

How does this compare to last year's forecast? Well, the adoption forecast is lower in the early part of the forecast but similar towards the end, as shown by the mid case, which is green, almost meeting up with last year's mid case, which is the gray line, by 2040. The mid case is 7 percent lower cumulatively than last year's mid case in 2030, but only 1.5 percent lower by 2040, the last available year of comparison, as, if you'll recall, 2024's forecast did not go up to 2045. It ended at 2040.

Slide.

This also means that market penetration is lower post ITC expiration. Fewer households will adopt after the ITC expires, as seen in the chart to the right. This decreased market saturation actually means that more households will adopt solar post 2035 in this forecast compared with the 2024 forecast, since there are more potential adopters out there in that situation post 2035.

Slide, please.

Meanwhile, storage sees an even bigger effect from the ITC expiration, as we forecast an 80 percent-plus decrease in annual capacity additions. But we do see long-term increases in two of the cases, in the mid ITC case due to ITC reintroduction and in the high case due to NEM turnover, where we assume customers who installed solar under NEM 2.0 will adopt storage at the same rate of NBT customers when they're switched over after 20 years, and that leads to quite a significant jump, especially peaking at 2043, which is not coincidentally 20 years after the last year of NEM 2.0.

Slide.

When comparing to last year's forecast, we actually see higher capacity in the short term. This was due to the higher than expected installation levels in 2025 that are reflected in this forecast. However, longer term, we do see lower capacity, specifically 15 percent in 2040, when comparing the mid case to 2024's mid case, which is again in gray and this year's is in green.

Slide.

I also want to briefly go over solar and storage pairing. Last year, we saw pairing numbers consistently going up from as low as 10 percent before the switch to NBT to over 70 percent in 2024. However, the data we've gotten in the past year show that the pairing rate appears to be leveling off in the mid-70s, which increases our confidence in using that value in our model for future years since it doesn't look like it's going to go up.

Slide.

Finally, a comparison of storage types. Over 70 percent of storage installations are currently paired with a PV system. Through the forecast period, only about 18 percent of storage capacity added is standalone, meaning the paired number will just continue to go up. And as a note about standalone storage, the vast majority of those installations are in the non-residential sector. We don't see it very much at all in the residential sector.

Slide.

This concludes my presentation. Thank you all for listening.

I'll now pass it over to Bobby Wilson, who will discuss hourly behind-the-meter distributed generation results.

MR. WILSON: Thanks, Mark.

Hello, everyone. My name is Bobby Wilson, and I'm a Distributed Generation Specialist in the Demand Forecast Unit at the CEC. Today, my presentation is on hourly behind-the-meter distributed generation forecast results.

Next slide, please.

Before we begin, here is a list of acronyms and initialisms you might see or hear in my presentation.

Next slide, please.

Okay. Now we'll take a look at hourly BTM PV results.

Next slide.

The biggest takeaway from the 2025 hourly PV forecast is the reduction of PV generation in the short term due to the elimination of the ITC. That reduction peaks around 2035.

After 2035, the mid case from this year's IEPR and the 2024 IEPR begin to converge to the same values. If we take a look at the second bullet point, we can see that in the two sub-bullets, in 2035, the behind-the-meter PV generation at the hour of peak demand is reduced by 250 megawatts in this year's forecast in comparison to last year. By 2040, that reduction is only 20 megawatts. Similarly, in 2035, the daily max generation, which occurs in hour 13, is reduced by 900 megawatts in this year's forecast. And by 2040, that reduction is 170 megawatts.

Okay, next, we are going to look at some charts of the BTM PV generation in this year's forecast.

Next slide, please.

Here is the average hourly PV generation for the first week of September in 2035. As you can see on this chart, the 2024 IEPR mid case, which is the gray line, and this year's high case, which is the red line, are about the same. This year's mid case is the green curve, which is below the 2024 IEPR. And you can see the 900 megawatt reduction in max generation and the 250 megawatt reduction in generation at the hour of peak demand on both the chart and the table to the left.

Next slide, please.

Okay, here we are five years later in 2040. The high case, which is the red curve, has now outpaced the 2024 IEPR mid case, which is the gray curve. And the 2025 mid case, the green curve, is at the same level as the 2024 IEPR mid case.

Next slide, please.

All right, this is 2045. Last year's forecast went to 2040, so there is no curve for the 2024 IEPR here. As we've seen on the previous slides, and this one too, the mid ITC case, the dark blue curve, which assumes the ITC is reintroduced in 2030, drives higher generation throughout the forecast period.

Now we'll take a look at hourly BTM storage results.

Next slide, please. Thank you. Next slide, please.

Okay, the ITC elimination also has an effect on BTM storage, reducing the amount of capacity that will be added in the long term. If we take a look at the second bullet point, we can see that in the two sub-bullets, in 2035, the daily max generation is 300 megawatts lower in this year's forecast than last year's forecast. By 2040, that difference is 220 megawatts.

Next slide, please.

Okay, this is the average hourly discharge for the first week of September in 2035. Here we are only showing a summer profile. When considering the impacts of a winter peak in the later part of the forecast, we would expect to see potentially new rate structures and different charging and discharging profiles. In 2035, we can see the reduction that we spoke about on a previous slide during hour 19 when daily max discharge occurs. The 2025 IEPR mid case, which once again is the green curve, is below last year's IEPR, which is the gray curve.

Next slide, please.

And the reduction continues to grow in 2040 -- or excuse me, the reduction decreases in 2040. The mid ITC case, the dark blue curve, has overtaken last year's IEPR, which is the gray curve.

Next slide, please.

And here we have 2045. Once again, there is no curve for the 2024 IEPR. As you saw in the previous slides and even more pronounced here, the 2025 high case, the red curve, is significantly higher than the other cases due to NEM turnover additions.

Next slide, please.

Thank you to our forecasting team, and I'll hand it back to Heather.

MS. RAITT: Great. Thank you, Bobby.

So next, we will go to Anne Fisher for some Q&A from the public.

COMMISSIONER MCALLISTER: Can I maybe ask maybe a quick clarifying question actually?

MS. RAITT: Oh, sure. I'm so sorry.

COMMISSIONER MCALLISTER: Yeah. Opens up some space for the dais. But I just have one quick question. All that, I got at the -- you know, been following this, so not surprised to see some of these results.

But let's see, Mark, did you -- I probably misheard, when you were talking about attachment rates, I thought I heard that they were sort of more consistent and higher in the non-residential space. Did I hear that right or --

MR. PALMERE: No.

COMMISSIONER MCALLISTER: No. Okay.

MR. PALMERE: The standalone storage is higher in non-residential.

COMMISSIONER MCALLISTER: Oh, okay, that's what I missed. Gotcha. Gotcha.

MR. PALMERE:

COMMISSIONER MCALLISTER: Okay. Okay. That makes sense. That makes sense. And is there appreciable standalone storage in the residential space, like single-family or small multiple family, or just --

MR. PALMERE: There's a small amount, like it's a non-zero, but it's not -- it doesn't have that much of an impact on the overall storage numbers.

COMMISSIONER MCALLISTER: I would be interested in your sort of take on why that might be the case. I mean, I think, you know, residential customers are sort of a little bit less, potentially less -- a little sacrifice of reliability, you know, sort of is not -- they wouldn't necessarily feel they want to make a big investment to get that tiny little bit of additional reliability or backup, or maybe they're getting gensets or something. I don't know.

But it seems like that's a little bit of an underutilized resource, you know, behind-the-meter batteries without PV attached, especially going forward.

So I wonder if we'll see more of that going forward.

MR. PALMERE: Yeah, we'll definitely keep an eye on that to see if those numbers change. There certainly is, I mean, as electricity, as time-of-use increase, there certainly is more of an incentive to have a battery even without solar. But, yes --

COMMISSIONER MCALLISTER: (Indiscernible.)

MR. PALMERE: -- I don't have one answer to --

COMMISSIONER MCALLISTER: Okay.

MR. PALMERE: -- to the question. But I would say generally, I think there's kind of an overlap in customers interested in solar and in batteries. So that's why we don't see a lot of them getting just the batteries. But, yeah, I mean, it is definitely a nuanced issue, and something we'll continue to look at the numbers to see if they change over the years.

COMMISSIONER MCALLISTER: I guess I asked partly because, you know, there are utilities in other parts of the world, of the U.S. who are offering standalone battery services as a -- you know, maybe they're more rural and they have more sort of outages in their weaker feeders. But they're offering, you know, subsidized batteries or just, you know, to work with the customer to dispatch and aggregate battery resources as a reliability tool, whether or not there's solar involved. And it's kind of an interesting approach.

But, yeah, so anyway, thanks a lot. Really appreciate that.

Commissioner Douglas, Commissioner Houck, any -- or Raja, any questions for Quentin or Mark or Bobby?

COMMISSIONER DOUGLAS: None from me, thank you.

COMMISSIONER MCALLISTER: Okay, great.

COMMISSIONER HOUCK: Yeah, I don't have any questions either right now.

COMMISSIONER MCALLISTER: Okay, great. Awesome. Yeah. Okay. Well, thanks. Thanks a lot.

And Heather back to -- or Anne, rather, back to you for a question, Q&A from the attendees.

MS. FISHER: Good morning. Yeah, thank you, Commissioner. So we have a few questions in the Q&A.

First question is, "Do these behind-the-meter storage figures include non-residential?"

MR. PALMERE: The forecast results do include both residential and non-residential. The pairing graph I shared of solar and storage pairing, that is just for residential. So I'm not sure which specifically you're asking about, but the forecast results do include residential and non-residential.

MS. FISHER: Thanks Mark.

Next question. "Do these figures include commercial, industrial, behind-the-meter storage?”

MR. PALMERE: Yeah. So industrial is -- commercial and industrial are both subsectors of non-residential. So they would all be included in the forecast storage numbers.

MS. FISHER: “How is behind-the-meter storage assumed to dispatch on reliability risk days? Will dispatch assumptions align with performance obligations under utility rate structures?”

MR. WILSON: Sorry, just unmuting. Yes, the reliability risk or event dispatch is not considered an IEPR, so that’s not part of the results that we presented.

MS. FISHER: Thanks, Bobby.

We have a number of comments from CalSSA (phonetic). There was one part of this that I did want as a question for you guys. So the question is, you know, how do we handle the ITC ending at the end of 2025 for residential solar and then continuing to 2027 for non-residential?

So Mark, could you speak to that a little bit?

MR. PALMERE: Yeah. I did want to clarify that we do include nuance on the incentives that I just didn’t have a chance to get into those details. But to clarify, we are aware of the continuation of the non-residential storage incentive and that is modeled in our -- included in our model. It’s just kind of a way of -- we’ve kind of modified the model to account for that even saying -- it’s kind of a technical thing, but it is considered and we are aware of it in terms of higher potential numbers in non-residential. So the effective cost with just the incentive for storage moving into the next decade is still taken into account. But, yeah, there just wasn’t time in the presentation to go into those details.

MS. FISHER: Thank you. Yeah, as to those other comments, we do encourage you to either provide a public comment at the end of the workshop today or submit a written comment.

Next question.

“Do your forecast assumptions include policy drivers such as battery incentives? And if so, incentives already exist at the local level and additional incentive programs are likely to be launched. Are those taken into account?”

MR. PALMERE: Yeah, we do assume, just like if you’re talking about like general, like for example, the ITC is considered and that's -- or has been considered and that’s why our forecast is lowered due to the changes to it.

In terms of local incentives, it’s just kind of a limitation to our model to capture something at that level.

But we do like take into account the current prices that are being paid by the consumer. So we have data from DG stats for that, the distributed generation statistics website from the CPUC to analyze current prices that are being paid.

And in terms of like future incentives, it's kind of unclear the fiscal limitations of SGIP in future years, so that's not currently reflected. But we definitely capture as much as we can in terms of other incentives beyond the major one.

MS. FISHER: Thank you. "How is behind-the-meter storage assumed to dispatch in general?"

MR. WILSON: Yes, for -- okay, I'm unmuted. We assume non-event based dispatch in accordance with peak demand shaving and TOU arbitrage. But for non-res storage, specifically dispatch, the dispatch assumption is that there's a blend of TOU arbitrage and peak demand shaving. And those rates and profiles were sourced from prior SGIP impact evaluations. For residential storage, the dispatch is in accordance with TOU arbitrage. And those were workshopped in a previous IEPR in 2023.

MS. FISHER: Thank you. "Would EV to grid application be reflected in behind-the-meter storage at residential level?"

MR. WILSON: Yeah, no, we don't include EV to grid in BTM storage.

MS. FISHER: Thanks.

“Did the CEC team look at public charging hubs for medium duty heavy duty vehicles based on a behind-the-meter microgrid, including chargers, solar and storage?”

MR. WILSON: I don’t think that was included either.

But Mark, you can correct me if I’m wrong.

MR. PALMERE: Not specifically, no.

COMMISSIONER MCALLISTER: Just, by the way, we are going to have the next session, the next presenters here on Transportation Forecast and electrification of transportation, so maybe they can address those transportation related bidirectional charging and the like.

MS. FISHER: Yeah. Great point.

I’m not seeing any additional. Oh, here’s a question that just came in.

“If next year’s IEPR Forecast shows that the 2025 behind-the-meter high scenario for paired solar and storage systems was realized, what issues does that create for CPUC and CAISO planning processes?”

And this may be more of a question for the Commissioners.

MR. PALMERE: Yeah, I don’t know if it’s asking about like the 2025 results in particular. Those, I mean, those are pretty similar among all the low, mid and high cases just because it's, we're looking at like one year forecast.

But if the question is like, if next year's forecast, the mid case is equal to this year's high case, then I mean, yeah, we would have to reassess. Obviously, that's, this forecast is a continuing process. And, yeah, I mean, given the big changes to the policy -- to policies, there is a lot of uncertainty right now. And we're hoping to get more certainty as we get more actual interconnection data through all of the changes.

I guess that's all I can really say about that now is we do keep -- we do constantly reassess. I mean, each year we either have a new forecast or an update. So if things change, we'll take them into account moving forward. Then, yeah, I mean, there's just a lot of uncertainty in general, so that's part of the process and why we have multiple cases. I mean, not just from solar and storage, but any other load modifier that gets forecasted.

MS. FISHER: Thanks.

"From a resource planning perspective, should we assume energy needs from behind-the-meter storage are fully resolved and netted from behind-the-meter solar, or should we include in broader energy sufficiency needs?"

MR. WILSON: Yes, for our purposes or for our assessment, we assume that all BTM storage is resolved by BTM solar, that the solar generated is charging the batteries.

MS. FISHER: Thank you. Next question. "Am I understanding correctly that your low and mid forecasts assume no storage retrofits?"

MR. PALMERE: That's correct. That's not a part of the mid and low case, just because right now, based on the data we have so far, there's not evidence to include it, at least at the same, compared to the optimistic high case that is assuming a good amount of retrofits.

But as I said, for the last question, that's something that we'll continue to look at the data. If we see evidence that it will be a continuing trend, then we would definitely incorporate it. But as of right now, it's not part of the lower cases, mid and low.

MS. FISHER: Thanks Mark.

I'm currently not seeing any new questions in the Q&A.

MS. RAITT: Great. Unless the Commissioners have more questions, maybe we can move on to the next part.

COMMISSIONER MCALLISTER: Yeah, no, thanks a lot, Quentin and Mark and Bobby, really appreciate it, and Anne as well. And really great to see numerous questions coming in from attendees, so thanks for your engagement. And yeah, hopefully that continues going forward for the rest of the day.

All right, nothing more from me, and I don't think from my colleagues here on the dais, so let's move forward with the Transportation Forecast.

MS. RAITT: Great. Go ahead, Alan.

MR. JIAN: All righty. Hello, everyone. Can you all see me? Everything good? Okay. Cool. All right.

Good morning, everyone. My name is Alan Jian and I'm a Forecaster in the Transportation Energy Forecasting Unit. Today, I'll be providing an overview of the draft results for the Transportation Energy Demand Forecast. I'll start by providing background on the forecast, including updates made since last year's forecast, and then I'll go over the annual statewide results. Afterwards, my colleague, Elizabeth Pham, will present the hourly forecast results. We'll hold questions until after the presentations are complete.

Next slide, please.

We have included this list of acronyms for those who are new to this subject area. In particular, I would like to highlight the definition of EV that we will be using for today’s presentation. The forecast we will show today focus only on plug-in electric vehicles and the associated electricity demand from them. We will not be discussing the electricity usage associated with the production and generation of other fuel types. The electricity associated with those facilities, such as oil refineries, is included in other parts of the CEC’s forecast.

So -- oh, next slide, please.

So first, some background on the forecast.

The forecast acts as a predictive tool to help assess future transportation energy demand. It is used by government agencies, utilities, fuel providers, and many others to plan infrastructure development, adjust energy policies, and implement emission reduction strategies. In essence, it enables better preparation for the evolving energy needs of California.

One of the key purposes that the forecast serves to inform is a balanced approach to the proactive planning for electrification. Overestimating the growth of transportation electrification could lead to overdevelopment of infrastructure and associated costs that could lead to affordability issues, and underestimating the rate of growth could lead to delayed development of needed infrastructure and prevent California from achieving its climate and public health goals.

At the simplest level, the transportation energy forecast achieves this by taking a pragmatic approach to determining how many and what types of vehicles will be on the road, the types of fuel they will use, how much they will travel, and other factors impacting their consumption of fuel.

Next slide, please.

We have two types of forecast scenarios, the baseline scenario, which reflects existing market conditions, including regulations that have been actively implemented, and the AATE scenarios, which stands for Additional Achievable Transportation Electrification. These AATE scenarios are designed to reflect the impact of policies across various scenarios that are difficult to implement solely in demand-side vehicle choice models, each of which is reasonably anticipated based on market, policy, and programmatic conditions.

Next slide, please.

With the increasing levels of uncertainty in the marketplace, the AATE scenarios provide an opportunity to show multiple paths forward, depending on how federal and state policies and other marketplace conditions may evolve over time. The accelerated growth of zero-emission vehicles in these scenarios result from new technological advancements, changing consumer demand patterns, future regulations, and other policy initiatives.

Next slide, please.

For the 2025 IEPR, we have included a series of AATE scenarios to reflect the changes in policy and significant amount of uncertainty prompted by recent federal government actions. We would also like to mention that given the high levels of uncertainty associated with tariffs on vehicles and components, we have not incorporated any tariff-related price impacts in this forecast.

In our analysis, we looked at different zero-emission growth rates across light-, medium-, and heavy-duty vehicle sectors, with a focus on how California may continue on a trajectory towards meeting its zero-emission vehicle goals. Each of these growth rates are then assigned to different AATE scenarios, which is depicted in this table. So, for example, the planning scenario, AATE 3, includes a high growth rate for light-duty vehicles while utilizing the baseline forecast for medium- and heavy-duty vehicles.

If you're wondering what goes into each scenario, don't worry. In the next few slides, we'll talk about the individual assumptions associated with each growth scenario. And as always, we welcome your input on which of these scenarios would make the most sense to use for infrastructure planning purposes.

Next slide, please.

So we'll start by discussing the light-duty forecast. In recent years, we have continued to update and improve the light-duty models that we use. The areas of light-duty vehicle usage we cover include personal vehicles, which are the dominant category of light-duty vehicle ownership, as well as commercial vehicles, government-utilized vehicles, and rental fleets.

We use choice models to determine what types of new or used vehicles will be purchased by different households, fleets, and other entities. Choices are based on desired characteristics and are informed by preference data gathered through tools like our California Vehicle Survey.

The baseline scenario focuses on projecting transportation energy demand in the state by existing vehicle fleets, standard fuel efficiency improvements, anticipated vehicle technologies, population growth, economic drivers, and travel behaviors. The baseline serves as a reference scenario for future transportation energy needs without taking into account significant policy or technology shifts, helping establish a point of comparison for planning purposes.

The AATE scenarios build on that baseline scenario and assesses how government policies, regulations, advanced vehicle technologies, such as upcoming zero-emission vehicle offerings, and associated fueling infrastructure further affect energy demand.

Previous Transportation Forecasts have modeled the impacts of recent regulations, such as the Advanced Clean Cars II regulation. In absence of this regulation, the AATE scenarios will focus on accelerated technology growth scenarios, some of which could be supported by future regulations, technology advancements, vehicle manufacturers reducing EV prices to offset the loss of the federal tax credit, and other measures.

I do want to mention that different organizations sometimes classify Class 2B vehicles in different ways. So for the purpose of this presentation, our light-duty modeling includes those Class 2B vehicles.

Next slide, please.

So now for the results. Historically, we have seen an increasing number of ZEVs and associated increases in market share for new vehicle sales. I would encourage those interested in finding out more details about California’s growing ZEV market to visit the Data and Reports section of the Energy Commission website, which has vehicle and infrastructure statistics available.

The baseline scenario shows continued growth in the ZEV population, which reflects both consumer adoption of new zero-emission options that are coming to market, and continued support from vehicle manufacturers that are planning to release new vehicles and updated models. The AATE 2 scenario reflects a moderate growth rate above the baseline, which could result from prospective future regulations and improved economics. The AATE 3 and 4 scenarios assume continued high growth that would rely on continued strong support from vehicle manufacturers, increased consumer interest, additional technology advancements opening the market to new segments of vehicle purchasers, and future state and local policy initiatives.

Next slide, please.

Here, we have included a comparison of the 2024 and 2025 ZEV population projections under AATE 3, the planning scenario. As you can see, there are not too many differences, most of which can be attributed to incremental improvements in our forecast, such as regularly updated inputs and improved modeling assumptions, some of which we described earlier.

I will point out that some of the leading drivers of change since last year, not just for these results but also for the forecast as a whole, are the increased market share of new vehicle sales and recently updated data on the market, including new models and improved technologies that will be released in the near future.

Next slide, please.

Similarly, we see changes between the 2024 and 2025 light-duty vehicle electricity Demand Forecasts. Many of the year-to-year differences seen here can be attributed to the changing mix of light-duty EVs and changes in travel behavior.

Next slide, please.

So now on to our medium- and heavy-duty modeling. Our baseline scenario includes input updates similar to those in the light-duty models.

In addition, it also assumes the continued manufacturing of a wide variety of vehicles by major vehicle manufacturers. The AATE 2 and 3 scenarios will utilize the ZEV growth rate from the baseline forecast. The AATE 4 scenario, however, will include an accelerated ZEV growth rate that could be spurred by continued technology advancements, accelerated manufacturing by major truck manufacturers, and future regulatory drivers.

With the uncertainty on how these factors may play out over the next few years, we have chosen to utilize a simple linear ZEV growth rate starting in 2031.

Next slide, please.

Here's a look at results for this year's medium-and heavy-duty ZEV on-road freight vehicle stock forecast. The scenarios utilizing the baseline growth rate are shown here in blue. I would like to reiterate that the AATE 3 planning scenario utilizes the baseline growth rate for these vehicles, given the uncertainty with prospective measures that might lead to the accelerated growth seen in AATE 4.

Next slide, please.

Shown here is the decrease in electricity demand when comparing planning scenario values from the Transportation Forecast with the 2025 forecast. This significant reduction in electricity demand is a result of changed growth assumptions between the years. The 2024 AATE 3 scenario assumed the implementation of the Advanced Clean Fleets Regulation. With the withdrawal of that regulation, the 2025 AATE scenario assumes baseline growth with no major fleet-side regulatory drivers for accelerated deployment of ZEVs.

Next slide, please.

For the overall transportation and electricity demand, including cars, trucks, buses, and other on-road vehicles, we see a decline from the demand in last year's forecast. As we discussed, this is primarily due to the lower ZEV truck adoption rate associated with the updated AATE 3 scenario.

Next slide, please.

That concludes our overview of the statewide 2025 Transportation Forecast. I would also like to give you a glimpse into what we'll be looking at for future forecasts.

As new policy initiatives are fleshed out, we will factor any relevant details into future modeling. Once tariff impacts on vehicle prices become stable, we will adjust the vehicle price considerations accordingly. We will also look at new data available on the behaviors of existing vehicle owners and prospective vehicle purchasers.

And one of the other key areas of interest will be to closely track the rapidly evolving autonomous vehicle sector and determine what impacts it may have on travel behavior, vehicle ownership, electricity demand, and other factors. As a lot of the information surrounding the growth of autonomous vehicles is highly speculative, we will refrain from making any major assumptions about these vehicles until more data is available.

And with that, I will turn the discussion over to Liz for the hourly forecast.

Next slide, please.

MS. PHAM: Hello, everyone. My name is Elizabeth Pham, and I will be presenting an overview of our EV load model and the associated hourly results.

Next slide, please.

First, let’s go over some of the terminology I’ll be referring to. Load shapes and load profiles are often used interchangeably. However, we use shape to mean the shape of the hourly load, often normalized, and use profiles to mean both shape and magnitude of the load.

Next slide.

So here is an overview of the EV load model. It takes in three types of input.

The first type are inputs from the IEPR Electricity Forecast. We have light-duty vehicles, medium- and heavy-duty vehicles, and bus energy.

The second type of inputs are our load shapes. Load shapes you would typically see at a single-family home, multi-family home, destination charging, which is away from home charging, or in-route charging, as well as commercial vehicles, government, rental. And we have load shapes for medium- and heavy-duty vehicles, as well as bus.

And the third type are our economic inputs. So we have EV TOU rates for each of the utilities, TOU schedules, so TOU rates differ based on on-peak, off-peak hours, the season, weekday, weekend, and whether it’s residential or commercial. TOU participation, which is the percentage of people participating in TOU rates. Price elasticity factor, which is the price response to electricity rates, and seasonality, which uses quarterly averages of monthly gasoline and diesel sales tax that we are assuming is indicative of electricity consumption.

So at a high level, our EV load model takes our IEPR Electricity Consumption Forecast, uses the base load shape to create an 8,760 hourly load profile, and then the load profile is shifted based on the economic input.

Next slide.

The results that we post online consists of two load profiles, one for light-duty vehicles and one for medium- and heavy-duty vehicles. However, our inputs for load shapes consist of many different types of charging patterns for both light-duty and medium- and heavy-duty vehicles.

For the light-duty vehicles, these include load shapes you would typically see at a single-family home, multifamily home, destination charging, which is away-from-home charging or en-route charging, as well as load shapes from commercial vehicles, government, and rental vehicles. And these load shapes were informed by ChargePoint data that we got in 2017.

For buses, we have load shapes for school bus, urban bus, these are buses within the city, such as public buses, intercity bus, which go between cities, such as Greyhound, and other bus, which encompasses airport bus, and shuttles, and these load shapes we got from Lawrence

Berkeley National Lab.

For medium- and heavy-duty, we have load shapes for vehicle classes with gross vehicle weight rating 3 through 8, also sourced from Lawrence Berkeley National Lab.

Next slide.

For assumptions, we are assuming gasoline sales tax informs light-duty seasonal electricity consumption, and diesel sales tax informs medium- and heavy-duty seasonal electricity consumption.

For our load shapes and price-elasticity factor, they are all the same for each of the utilities. We recognize that there could be regional differences for these inputs, we just don't have better data to inform them yet. We're hoping to improve these inputs by using AMI data, or advanced metering infrastructure data, but that is still to be determined if possible.

Another assumption is that today's charging behavior will stay the same into the future.

And lastly, we assume that EV rates, the ratio between off-peak and on-peak hours, remain the same throughout the forecast years.

Next slide.

For the inputs, I just wanted to go over what is different compared to last year's inputs.

For EV TOU rates, every year we update the EV TOU rates for each of the utilities, so those were updated as of October 2025.

Seasonality was updated.

And then for load shapes, electricity factor, and TOU participation, these all stay the same as well.

Next slide, please.

Our seasonality uses quarterly averages of monthly gasoline and diesel sales tax from the California Department of Tax and Fee Administration. So we assume that the seasonal pattern in the electricity consumption for light-duty vehicles and medium- and heavy-duty vehicles mirrors those observed in gasoline and diesel sales tax respectively. So this assumption is based on the premise that vehicles miles traveled for gasoline and diesel vehicles follow similar seasonal trends as those for electric vehicles.

So on the left side is an index chart for light-duty consumption, and on the right side is an index chart for medium- and heavy-duty consumption. Both have similar distributions. You'll see lower energy consumption in the winter months, so month one, two, and three, and more energy consumption in the summer months, so month seven, eight, and nine. Essentially, seasonality shifted more load to the summer months than the winter months.

Next slide.

For the light-duty results, here is a comparison between last year’s and this year’s load profile. We’re currently looking at a load profile from 2035, a weekday in September for the CAISO system. The CAISO system is essentially PG&E, SCE, and SDG&E. Much like the annual results Alan previously showed, the 2024 and 2025 projections are closely aligned.

Next slide.

For the medium- and heavy-duty results, here is a comparison between last year’s and this year’s load profile. Again, we’re looking at a profile from 2035, a weekday in September for the CAISO system. Significant reduction in overall load and changing shape resulted from the reduction in EV trucks adoption that was discussed earlier from Alan’s presentation.

Next slide.

Here we have the overall load profile for light-duty vehicles and medium-heavy-duty vehicles for the CAISO system. Again, we’re looking at a profile from 2035, a weekday in September. We can see a lot of nighttime charging peaking around 11:00 p.m. to 1:00 a.m., less charging in the early mornings around 5:00 to 6:00 a.m., and then peaking again around 9:00 a.m. to 11:00. This mid-morning peak is mainly due to our light-duty commercial and government rental vehicles and away-from-home charging, and then load decreasing around peak hours from hours 16 to 21 when TOU rates are more expensive.

Next slide.

With that, we'd like to thank you for your attention and happy to answer any questions.

Anne or Quentin?

COMMISSIONER MCALLISTER: Thanks so much, Alan and Liz, both, really interesting.

I did have one, just one clarifying question for you, Liz. I think you said the charge point data was from 2015 or 2017.

MS. PHAM: Yeah.

COMMISSIONER MCALLISTER: I think it said 2017 on the slide.

MS. PHAM: Yeah.

COMMISSIONER MCALLISTER: Is there any -- so that seems, you know, given the dynamism in this sector for light-duty, I wonder if there are any -- is there any reason to believe that sort of charging patterns and habits and the like have changed since 2017?

MS. PHAM: So our model shifts the EV load based on TOU rates, so the benefit of using data from 2017 can provide a baseline for understanding the typical load patterns and the initial impacts of TOU rates when it's potentially less common.

COMMISSIONER MCALLISTER: Oh, okay.

MS. PHAM: But, yeah, we do recognize that our data is outdated, and so we currently have AMI data that we're hoping can better inform our load shape.

COMMISSIONER MCALLISTER: Great. Yeah.

MS. PHAM: -- (indiscernible).

COMMISSIONER MCALLISTER: Okay, great. That's where I was going to go with that. Because, I mean, we do, you know, we do have the DMV data, like we know where the cards are registered and we can -- it seems like we can -- we could put together a pretty -- get some pretty good insights from looking at those, especially now that we have AI and we can like look at it --

MS. PHAM: Yeah.

COMMISSIONER MCALLISTER: -- just figure out how to use these big data sets more efficiently. Yeah, so definitely strongly encourage that.

I want to -- yeah, and just, it's a bummer to see the impact of the, you know, the withdrawal of the clean -- of the Advanced Clean Fuels rules and not surprised that it has that impact. So thanks for sort of laying that out.

And I guess on the light-duty, you know, I'm not as tuned into -- you know, Commissioner Skinner is lead on sort of a transportation, you know, market dynamics and those issues directly related to transportation. But I guess I'm wondering on light-duty, it looks like you had not that much difference between last year's and this year's forecast when, you know, again, the federal kind of, you know, posturing has changed. And, you know, the governor's executive order for 2020 -- or 2035, you know, that would require a light-duty to have, to be zero-emission, I guess I'm wondering is, you know, that's a state-level initiative that has not gone away, but certainly the federal dynamics would seem to impact it, especially, you know, no more tax credits and that sort of thing.

So I was a little surprised to see the, the light-duty kind of roughly even, and even exceeding the 2024 in the out years. So is that just a reflection of the strength of the California EV market or what?

I see Andre came on.

MR. FREEMAN: Yeah. So thanks for that question. It's a question we get very commonly. And I know Alan mentioned earlier in the presentation, we are not factoring in --

COMMISSIONER MCALLISTER: Yeah.

MR. FREEMAN: -- tariff impacts.

COMMISSIONER MCALLISTER: Oh, right. Yeah.

MR. FREEMAN: So the current forecast does look at the removal of the tax credit, which did have an impact in, especially, in the next couple of years.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. FREEMAN: We have seen some of the OEMs out there trying to adjust their retail prices just on their own, maybe taking less of a profit, a bigger hit to kind of offset that differential. But we do expect when we come back to you with the 2026 forecast, we'll have data on how the tariffs have impacted retail prices, both in the light and medium and heavy duty sides of the equation, since there are tariffs that impact the full spectrum vehicle types. And then we'll, again, barring anything, you know, new coming out of the federal government, we will likely see some type of negative impact built into next year's forecast.

COMMISSIONER MCALLISTER: Okay. Okay, great. Thanks, Andre. I appreciate that.

Quentin, did you want to chime in as well?

MR. GEE: Yeah, thanks, Commissioner McAllister. Yeah, I think Andre got to a lot of it.

I would point out that the AATE 2 scenario does capture a little bit. So the AATE 3 scenario for light-duty sort of has that sort of linear increase in proportion of new vehicle sales. The AATE 2 does not until a later date, I think Alan may have mentioned that --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- but the thinking is that there might be additional market transformations or new policies further down the road that we anticipate in line with things like the governor's executive order. And so I think that AATE 2 sort of serves as kind of a balance point between --

COMMISSIONER MCALLISTER: Interesting.

MR. GEE: -- a pure kind of like, if everyone's frozen in time today and their attitudes and the EV, you know, model sort of just stays put with those consumer preferences, that's kind of the baseline. And we're expecting something sort of in between there with AATE 2.

COMMISSIONER MCALLISTER: Okay. It sure seems at the top end of the market, like for light-duty, that there -- it would be interesting to know sort of the residence time of the first buyer, the car with the first buyer, like with EVs versus other types of cars. Because it seems like there's a certain percentage of folks that are buying new cars, and then sort of either on lease or whatever, but then actually going to the next iteration as battery technology and bells and whistles, it seems like that's -- the EV sort of dynamic there is different than the ICE dynamic. I don't know that, it's just a gut.

MR. GEE: Yeah.

COMMISSIONER MCALLISTER: And so it would be interesting to sort of pay attention to that. And it sure seems like there's a very robust and growing market for second or used, you know, pre-owned EVs as well. So those dynamics do seem kind of new. And so it'd be good to sort of understand how those impact the growth of the market over time.

MR. GEE: Yeah, we are tracking that. I mean, once a vehicle is introduced as a new vehicle sold, it's kind of in the population.

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: We do have vehicles leaving the state in our stock model.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. GEE: But we want to make sure we true that up and get a better sense of, you know, like, are these, a lot of these 2022 cars that have been -- EVs that have been leased are now, you know, going into the used market. A lot of them tend to leave the market, leave California at least. But, you know, we want to see like, well, hold on, are they leaving? We're going to be conducting some analysis on the sort of the rate at which the vehicles are staying in state.

But, yeah, we're tracking things. I mean, a lot of interesting things in the used market could have impacts later on down the road in the new market as people become more comfortable with EV technology.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. GEE: Maybe they buy a used one because they're not really sure and then they get more comfortable with it and those sorts of things.

We're also trying to track battery investments as well. We weren't able to get the latest data ready in time for the workshop. But we've reported in the past that battery facility, manufacturing facilities in the United States have been growing quite a bit. You know, there have been some setbacks and we're looking to get the latest data, but we're finding that the amount of installed capacity that we expect is well-suited to have a large amount of -- to support a large amount of electric vehicles in the future, which could affect things like prices and other things pertaining to potential market transformations.

COMMISSIONER MCALLISTER: Yeah. Yeah, that's really interesting. And prices seem to be coming down and this parity issue of when actually the lines cross, you know, just on the initial investment, right, that seems to be like not too far out. And then like obviously --

MR. GEE: Yeah.

COMMISSIONER MCALLISTER: -- across ownership is already lower, so, for many cars. So --

MR. GEE: Yeah.

COMMISSIONER MCALLISTER: -- yeah, so this is great. I really appreciate it.

And I want to open up to my colleagues on the dais, Commissioner Houck, Commissioner Douglas, or Raja, if you want to ask any questions as well. We're a little bit ahead of time. So we do have some time. We've got 10 minutes or so. We're a little bit ahead of schedule. I'm not hearing questions.

MR. RAMESH: No, no questions from me at this point.

COMMISSIONER MCALLISTER: Okay, great.

Either Commissioner Douglas or Commissioner Houck, any questions for the transportation panelists? Going once.

All right, so let's see, I guess, Anne, do you want to -- are there any questions from the attendees that we want to, we need moderation?

MS. FISHER: Yes. Thanks, Commissioner.

COMMISSIONER MCALLISTER: Great.

MS. FISHER: We do have a couple of questions in the Q&A.

First question:

"Is there a process to integrate future grid considerations from SB 100 or the IRP processes to assess future TOU periods to assess and or drive different overnight charging behavior?" They give an example, "9:00 p.m. to 12:00 a.m. as emerging as a key risk period in the late 2020s."

MS. PHAM: So right now there is no process in place. But I think that's a very interesting point, so we'll definitely consider for the next IEPR.

COMMISSIONER MCALLISTER: I want to just double-click on that question.

The carbon content is not the same as price at this point, there's a little bit of a disconnect, you know, in the time-of-use rates that are there. And we're having this same conversation in the Flexible Demand Appliance Standards context, trying to show, okay, if it's cost effectiveness, you know, dollars, or is it decarbonization, and those two things don't necessarily, you know, map together very well at this moment.

And so the nighttime charging, you know, the forcing things out of TOU, and then into nighttime isn't necessarily the best decarbonization strategy. But it would -- it does save consumers money. So we'd love to, you know, work with you all to unpack that.

MR. GEE: Yeah, that is an important dynamic for us to consider. It's something. You know, we do show that the model does indicate that there is growth towards a little bit more daytime charging. In the model results, we have, you know, a little bit more of a -- if you look at the light-duty load towards the middle of the day, there's a little bit of load being shifted towards that. But the time-of-use rates do incent a lot of people to charge at 12:00 a.m., or in I think, in the So Cal Edison territory at 9:00 p.m.

Those, you know, that is something that we want to like have more fully considered conversations about with, you know, all kinds of different folks. On the one hand, you know, we have this suspicion, like you mentioned, Commissioner, with the issue around carbon emissions and nighttime activity and nighttime -- not peaking necessarily at night, but high, high amounts of load at night. That is something that, you know, the forecast says, like, if you continue to keep things this way, right, this is what you can anticipate.

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: So we have to balance that between what kinds of goals do we want to have towards encouraging more zero carbon or low carbon transportation options.

So that's something that we will be continuing to talk with different partners with on this issue, because it is a sensitivity, right?

COMMISSIONER MCALLISTER: Right.
MR. GEE: We don't want to -- we're producing a forecast that says, like, here's what we expect it to be.
COMMISSIONER MCALLISTER: Yeah, what's happening, yeah.
MR. GEE: We can't say, like, well, if everything works out just perfectly, right, then, you know, we'll have this, everything happen here.
COMMISSIONER MCALLISTER: Yeah. Yeah.
MR. GEE: So we're trying to make sure that there are policy insights as well from the --
COMMISSIONER MCALLISTER: Yeah, exactly. I mean, I think that's your value here in the analysis coming up with some, well, you know, actually, there might be a need for policy to sort of emphasize middle of the day versus the middle of night.
I guess a related question is, and this isn't -- well, it's sort of, kind of related to the forecast, but slightly different issue. Are you sort of up to date on efforts to avoid just like this spike at midnight or at 9:00 p.m. or whatever, like when the TOU expires and a bunch of cars are already plugged in and, boom, they sort of start charging all at once when the TOU period expires? You know, that is a reliability, potential reliability issue and could drive a peak right in that hour --

MR. GEE: Yeah.
COMMISSIONER MCALLISTER: -- at least locally. So are you looking at that?
MR. GEE: So that cuts in. I think that, that question kind of cuts at two separate levels on, you know, we're --
COMMISSIONER MCALLISTER: Yeah.
MR. GEE: -- we're trying -- the forecast overall is sort of a system level forecast --
COMMISSIONER MCALLISTER: Yeah, exactly.
MR. GEE: -- that is thinking more about kind of like resource planning and procurement and those sorts of challenges. Right now we're not seeing, even with the TOU rates kind of pushing a lot of people to charge at midnight, we're not seeing I think a midnight peak in the load model anytime within the forecast period.
COMMISSIONER MCALLISTER: Yeah.
MR. GEE: We are seeing, you know, you sort of draw a chart --
COMMISSIONER MCALLISTER: It would be a transient spike; right?
MR. GEE: -- at what is 12:00 a.m. compared to --
COMMISSIONER MCALLISTER: Yeah.
MR. GEE: I'm sorry. What's that?
COMMISSIONER MCALLISTER: It would be like a

transient spike; right? So a potentially reliability issue, but not necessarily impacting like average load shapes or the forecast.

MR. GEE: Yeah. So at the grid level, we're seeing it maybe 12:00 a.m. compared to the peak, you know, gets a little closer to the peak, but doesn't become the peak.

COMMISSIONER MCALLISTER: Yeah, exactly.

MR. GEE: However, I think, as you mentioned at a distribution level, or even at a local, you know, direct like residential transformer that's serving like --

COMMISSIONER MCALLISTER: Mm-hmm.

MR. GEE: -- you know, six to ten homes; right? That can be a concern --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- if everyone there has an EV and has it set to a 12:00 a.m. charge.

So yeah, we are thinking through a lot of these things around our demand flex tool and some other --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- things that help with managed charging. Right now, time-of-use is a great way to encourage people and offer people an opportunity to save money and actually drive for way less per mile, cost per mile than gasoline alternatives. But there is this kind of challenge about getting people to do it in such a way that it doesn't create additional problems as more and more people own EVs. So we are --

COMMISSIONER MCALLISTER: Great. Okay.

MR. GEE: -- going to be using that in our demand flex tool and thinking through that more.

COMMISSIONER MCALLISTER: All right. Thanks for all that context. I really appreciate it.

So back to you, Anne, to moderate additional questions.

MS. FISHER: Thanks. Yeah. And I saw Nick Pappas (phonetic), who asked the initial question, put some additional comments in the chat, so thanks. That was a great conversation on that topic.

Next question.

"On the TE load modifiers, stock of the medium duty heavy duty vehicles forecast on slide 12, is it possible to get the vehicle count forecast detailed by vehicle class for 2030 and 2035?

MR. JIAN: Yeah, sure. I mean, for those sorts of like data requests, you can reach out to me or Andre, and we can help you out with that. So, yes.

MR. FREEMAN: And for those who haven't seen it before, at the end of every IEPR cycle, we post all the details from our Demand Forecast to what's called the

Planning Library. So we'll be able to provide that link to folks once it's released, but it will have the forecast down at the, broken down by individual vehicle class and fuel type as well.

MS. FISHER: Great. Thanks, Alan and Andre.

Next question. Sorry, my chat just jumped.

"Would it be fair to say, given the various uncertainties discussed today, that this forecast is more speculative than in the past?"

MR. FREEMAN: You know, that's a great question, Andy. You know, every year there's a lot of uncertainty associated with the transportation sector. You know, it's -- I don't -- I wouldn't say that one year is much more speculative than the others. When we release the forecast this year, for example, we try to outline the areas that we -- of high uncertainty, that we aren't incorporating into the forecast, such as tariffs this year, which you heard. We do expect to see those impacts over the next 6-12 months and be able to integrate that into the 2026 IEPR.

But even if you look at last year's Transportation Forecast, you know, we did model out all of California's existing or pending regulations that were there at the time. And we did have to give a caveat that some of them did need additional approvals at the federal level, so there was that uncertainty outline there.

So I don't want to tag, you know, various years as being more or less speculative than another. I do think that there's a lot more uncertainty this year on the price side for vehicles, primarily because of tariffs and other impacts. But I wouldn't say that it's significantly different than last year, because as I said, each year, there are various areas of uncertainty that we try to highlight alongside the forecast.

MR. GEE: Yeah, and I would add to Andre's point that, yeah, I wouldn't characterize this forecast as speculative. We have produced more scenarios to account for the various uncertainties. And, you know, as, you know, the Commission and our public agency partners sort of talk these scenarios through, and the combination of them all, and how that should impact the forecast, how they should interrelate to the forecast overall, I think that we will come to a decision that a Planning Forecast and a Local Reliability Managed Forecast that we can feel confident with is suitable for planning.

So, yes, there's a lot more variety in the scenario. So I guess in that way, there's more speculativeness in a very broad way. But I wouldn't want to characterize it as just kind of like, well, you know, like, what if, you know? So not quite sure exactly what you mean by the term “speculative,” but there is more variety in the forecast outputs across the load modifiers.

MS. FISHER: Thanks, Quentin and Andre.

Next question.

“Regarding TE and the baseline, AB 2700 requires including in distribution planning and investments, all the CARB regs. Does the baseline forecast include all the CARB recent regs that have waivers, ships at berth, SORE for forklifts, cargo handling, airport GSE, and also air district regs? Does the on-road include CARB regs such as clean mile standard and airport shuttles?”

MR. FREEMAN: So the forecast that we showed today was just for light-, medium- and heavy-duty on-road vehicles. And those do include the kind of pre-existing CARB regulations that were put in place prior to this year, including Clean Mile Standard, Airport Shuttle, and others. It does not incorporate things like Advanced Clean Cars II or Advanced Clean Fleets, which was drawn, which we talked about previously.

For some of those off-road transportation sources that you mentioned, and also the SORE regulation, we do have off-road equipment incorporated into the larger forecast beyond the Transportation Forecast. So, yes, those impacts are baked into kind of the larger electric and other fuel type demand that the CEC forecast puts out.

MR. GEE: Yeah. Yeah, just to kind of add on a little bit more, the -- as Andre mentioned, these are not load modifiers in the strict way that we're defining them here, but that we do incorporate them in the sector models, and those factors are considered there. So we do have, I believe we do have some information pertaining to that that we could post in the planning library.

MS. FISHER: Great. Thank you.

Next question.

"Someone mentioned that there's a slight shift for midday charging in the forecast. Does the model account for how as EV adoption expands to broader demographics, there may be more midday charging from drivers who can't install a charger at home, for example, renters?"

MR. GEE: Yeah, that's precisely what the model's doing there. We do anticipate more what we call away-from-home charging that would capture things like fast charging and other what we might call, what one might consider destination charging, where you arrive like at a hotel and you plug into a Level 2 charger at that location. So that's -- we are anticipating more of that.

We do have a distinct load shape for multifamily homes, which are best captured by renters versus single family homes, which oftentimes have some kind of direct capability to charge either Level 1 or Level 2 at the home.

MS. FISHER: Thanks Quentin.

And I see there's kind of a related question more on the medium-duty/heavy-duty.

"Are you seeing any difference in the medium-duty/heavy-duty charging patterns, depot versus public charging plaza or otherwise, due to ACF?"

MR. GEE: Well, we are not including the ACF rule in this year's forecast directly, or at least not in the AATE 3 scenario. We are including something akin to it there in the AATE 4 scenario, but we're not monitoring directly. The forecast is not capturing the precise sort of patterns associated with how that regulation works without and depot versus -- depot charging versus public charging.

The load shapes do capture, the medium- and heavy-duty baseline load shapes do capture a broad array of intended charging. And we are going to be working -- we are currently working with the CPUC on what's called TEPP, or the Transportation Electrification Proactive Planning, effort in further breaking out depot -- excuse me, plaza, MDHD plaza charging or public charging as a distinct component versus depot charging.

Andre, was there anything you wanted to add on to that?

MR. FREEMAN: Yeah, I was just going to add in because I know we've got a -- we've had a couple of questions on, you know, how charging patterns might change over time due to TOU changes, regulatory changes, you know, just natural changes in consumer behavior of how and when they're charging their vehicles.

I did want to mention that kind of outside of this IEPR proceeding, the Energy Commission does have other efforts such as the infrastructure planning activities that our Fuels and Transportation Division is on point for. And as part of those activities, they both monitor and develop reports that really try to stay on top of the ever-evolving world of light-, medium- and heavy-duty vehicle charging.

And through some of those efforts, we're collecting more data, getting more insight from people, for example, for this question, for charging companies who have developed depots and who are looking at prospective corridor or other charging needs to really start providing us more and more data that we can integrate into the future forecast that might change up some of those shapes that you've previously seen in our presentation.

But we're really looking for data that will help drive our understanding of how the market's changing. And I think as far as impacts from something like ACF go, that’s still a relatively recent occurrence. So hopefully, you know, throughout later this year and early next year, we’ll start to see more data that will help us kind of refine that charging shape for next year’s forecast.

MS. FISHER: Thank you.

Next question.

“Are you working on adding additional spatial granularity on your TE forecasts so they can support distribution planning more? Is that the forecast zone assignments?”

MR. JIAN: I guess I can chime in on this one. So we do actually disaggregate our like TE forecast a little bit further with something called the load bus allocation. So that helps disaggregate it down to the substation level.

That being said, yes, I mean, we are still like very interested in like improving the spatial granularity of like this forecast itself. But, yes, so to answer your question, yes.

MR. FREEMAN: And also, as Quentin mentioned earlier, we are working very closely with the teams at the Public Utilities Commission, and also teams for most of the major utilities as they try to kind of grapple with their own internal forecasts for, you know, exactly where this load’s going to appear, what type of distribution and transmission level upgrades are going to need to happen. So there’s a lot of internal and external conversations going on in that space.

And as Alan mentioned, you know, as we get more and more data, we will utilize that to kind of improve our existing processes to put out a more granular forecast and continue to work with those other folks who rely on using our Transportation Forecasts for their own purposes.

MS. FISHER: Great. Thanks, Alan and Andre.

“What significance do you assign to workplace charging in 2035?”

MS. PHAM: Is this question kind of asking how much of the charging, like what percentage of the charging is dedicated to workplace charging? If so, then it’s kind of significant in 2035. It’s about like 40 percent, which we could rethink if that’s too aggressive for people.

MR. GEE: Yeah, we do. Yeah, it’s a little bit unclear exactly how to parse out how much is workplace versus other DC -- you know, versus other charging.

But, yeah, Liz is right that we’ve got a good chunk of charging that occurs away from home in, say, forecast year 2035, more so than occurs away from home today. Away from home is a broad category. As you might imagine, that could include DCFC, you know, the fast charging, you know, that can charge your car in, you know, 15 to 30, 40 minutes versus Level 2 charging where you might imagine someone could show up to work, plug in for four hours or maybe the whole day and charge their car up you know, while they're sitting at work or something.

Right now, you know, as Liz mentioned earlier, we're doing a lot of AMI, or advanced metering infrastructure, analysis. Right now, it's hard for us to fully parse out exactly like workplace charging versus -- we only have meter data. So we can tell what's happening at a fast charging site and we can tell the charging that's happening at a home with an EV, but we can't necessarily tell what's happening at a big, huge warehouse site or a big, huge retail site that installed like 10 chargers on the same meter. That's a little bit harder for us to parse out, but we are going to continue thinking through how to best assess workplace charging and the dynamics there.

MS. FISHER: Yeah. Thanks, Liz. And thanks, Quentin.

That's the last question that I'm seeing in the Q&A, so -- oh, I saw Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. I really appreciate this interaction and thanks for all the attendees for asking great questions. I wonder about institutional and fleets. And I was distracted just for one second to do something else that came in, so maybe you mentioned this, but I wonder sort of, you know, how you're thinking of that or how you actually are paying attention to that and getting data about it and sort of figuring out how to incorporate the fleet side of things into the forecast?

MR. GEE: Sorry, Commissioner McAllister, when you say fleet, do you mean like a fleet of light-duty cars or do you mean --

COMMISSIONER MCALLISTER: Yeah, or school buses or --

MR. GEE: Or school buses.

COMMISSIONER MCALLISTER: -- you know, police. I mean --

MR. GEE: Yeah.

COMMISSIONER MCALLISTER: -- a lot more of that is going to be coming; right? And so --

MR. GEE: Yeah.

COMMISSIONER MCALLISTER: -- yeah, both. I guess it applies to both light and medium and heavy -- or light and medium, I guess. But, yeah.

MR. GEE: Yeah, so when it comes to things like school buses, I think Liz mentioned earlier in her presentation that, you know, we do have a school bus load shape --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- we have school bus population --
COMMISSIONER MCALLISTER: Okay.
MR. GEE: -- so that's pretty straightforward to do.
COMMISSIONER MCALLISTER: Right. Yeah.
MR. GEE: We are assigning that mostly only at the forecast zone level. When it comes to, say, light-duty fleets, we do have -- so our light-duty model does have different types of light-duty cars. So there's private or personal vehicles, there are commercial vehicles, there are government vehicles --
COMMISSIONER MCALLISTER: Oh, okay.
MR. GEE: -- and there are rental vehicles.
COMMISSIONER MCALLISTER: Okay.
MR. GEE: So we have four categories.
COMMISSIONER MCALLISTER: So the counties and cities that are transitioning over to electric, you've got those covered? That's my, I guess, my question.
MR. GEE: I'm sorry, could you say that?
COMMISSIONER MCALLISTER: The counties and cities and the local governments and, you know, the larger, the institutions that are moving to electric, you have good information and are paying close attention to that? That's, I guess, that's what I'm getting at.
MR. GEE: Yeah, we do have --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- we do have those different fleet types and different load shapes for them.

COMMISSIONER MCALLISTER: Great.

MR. GEE: And different load shapes for them.

COMMISSIONER MCALLISTER: Great. Perfect. All right. Well, thanks.

I just want to give one more opportunity to others on the dais, Commissioner Douglas or Commissioner Houck, if you wanted to follow up with any questions. And we’re almost back sort of on schedule here.

COMMISSIONER DOUGLAS: No questions from me. Thank you.

COMMISSIONER MCALLISTER: Okay, great. Great. Well, thanks. Thanks to all of you for really insightful presentations. Inspires a lot of confidence in your work and really appreciate the insights.

MS. FISHER: Thanks.

COMMISSIONER MCALLISTER: Great. So, I think, Heather, we’re going to Asish Gautam --

MS. RAITT: Yes.

COMMISSIONER MCALLISTER: -- to talk about the known loads.

MS. RAITT: Yeah. Great.

COMMISSIONER MCALLISTER: Hey, Asish.

MR. GAUTAM: Hey. Hello, Commissioner McAllister. My name is Asish Gautam and I'll be going over the draft impacts for the known loads for this year's IEPR Sales Forecast.

Next slide, please. The known loads -- thank you.

The known loads dataset contains requests from utility customers to energize new load. It is used in the CPUC's DER proceeding. And this proceeding is meant to encourage proactive distribution system planning to meet various goals, including building and transportation electrification.

Another focus of this proceeding is to identify local areas in need of infrastructure investments for future GRC cycles. The IOUs are including customer energization requests captured in the known loads dataset as part of their efforts to support distribution planning.

The utilities note that projects captured in the known loads dataset show potential for more load growth in the near term than what is reflected in the IEPR system forecast. So our interest in working with the known loads dataset for this IEPR cycle is to use it as a way to bridge the gap in load growth occurring in the near term.

And so we worked with the CPUC to issue a data request to the IOUs to collect project-level data in the known loads dataset. It gives an example of some of the fields that we collected on. And then, to the right, I show examples of the different types of loads that's captured in the unknown loads dataset. You can see there's different types of housing development and various commercial buildings that customers are interested in constructing and eventually energizing.

Just a quick note that for this analysis, we are excluding projects dealing with transportation electrification as we have a separate forecast for transportation, which we just covered, and that will be handled by Quentin and his team.

Next slide, please.

I wanted to go over some of the assumptions we made regarding the known loads data when it came to translating the capacity requested to sales.

First is the project cancellation rate. While the known loads data is considered to have some degree of certainty that the projects will finish construction and be energized, we do know projects do get canceled, and so there is some degree of uncertainty with projects listed in the known loads dataset. We used the August 2025 filing by the utilities to come up with the cancellation rates.

The second area I want to discuss is the ramp rate. Our assumption for ramp rate is meant to address the lumpiness associated with projects finishing construction, but that doesn’t mean that 100 percent of the load will come online just as construction is completed. As an example, if a 100-unit apartment building finishes construction, it doesn’t mean all 100 units will be occupied right away. It takes some time, so we made some assumptions about how load will materialize over time.

The next assumption we want to discuss is the utilization factor. This factor is meant to adjust the capacity requested to reflect what we think will be the actual peak demand. However, based on the use case, you may actually want to use 100 percent of the capacity requested, especially in the case of distribution system planning where you’re assessing local infrastructure needs.

But for load forecasting, we need something a little different where we are trying to forecast consumption. Generally, we don’t expect customers to use 100 percent of the capacity requested all the time, so our challenge is to find the balance between using a utilization factor that is too high and risking overestimating sales consumption. At the same time, we don’t want to use a low utilization factor or we may underestimate consumption.

Next slide, please.

This slide shows the utilization and cancellation rates by IOU. Again, regarding utilization factor, as I mentioned earlier, we don't expect customers to use 100 percent of the capacity requested, so that is the reason for this adjustment.

For this cycle, we were able to obtain meter data on completed projects for PG&E to look at how completed project from the known loads dataset, how their maximum demand varied monthly relative to the capacity requested in the known loads dataset, and we were able to estimate an average utilization factor for the three different load sectors there. You can see for industrial sector for PG&E, we estimate about 53 percent utilization factor, 65 percent for commercial, and almost 100 percent for ag.

We did not get meter data for Edison, but we understand that SCE makes an adjustment to capacity requested by customers to account for what they believe will be the estimated peak based on Edison's experience working with customer utilization requests.

We encountered an issue with AMI data for SDG&E, and we were unable to reconcile our meter data for SDG&E completed projects, but we continue to work with SDG&E and our IT Team to resolve this issue. And so for SDG&E, we try to keep the utilization factor close to SCE.

We do have an interest in continuing this meta-analysis for the next IEPR cycle, so we do hope to reach out to SCE to get more meter data, to get meter data, and hope to resolve our issue with the meter data we have experienced for SDG&E.

Next slide, please.

This slide, it's going to show our overall methodology for how we translated capacity requested to annual sales. Starting from left and going to the right, we start with the assumptions that I just discussed, along with information for the known loads data set, such as capacity requested, the customer sector, and the energization date. And then we apply load profiles to estimate annual sales and compare the load growth from the known loads to our baseline forecast of sales by a sector. We are only including the incremental portion of known loads that exceeds our baseline forecast to avoid double counting load growth.

And I just want to emphasize that since this is our first time looking at the known loads data set, we are recommending that the impacts from known loads only be included in the local reliability scenario to limit downstream impacts to other proceedings that rely on the IEPR Demand Forecast as an input.

Okay, next slide, please.

And this slide shows the capacity, cumulative capacity of projects for PG&E service area, again, excluding transportation projects. For 2026, we expect about 3,500 megawatts online, growing to about 4,500 megawatts by 2030. Just under 80 percent of the capacity is in the non-residential sector, and just a little over 20 percent in the residential sector.

Next slide, please.

In this slide, we show the result of applying the assumptions that I discussed earlier and our methodology to translate the capacity to annual sales. Here we show sales for PG&E to increase by just under 11,000 gigawatt hours by 2026 and growing to just a little over 13,000 gigawatt hours by 2030. Roughly three quarters of the sales is in the non-residential sector and about a quarter in the residential sector. For reference, by 2030 the increase is about 15 percent, 15 percent of PG&E's 2024 reported sales. So this is quite a bit of load expected to come online fairly quickly.

Next slide, please.

And this slide shows the capacity of projects in Edison's territory, again, excluding transportation projects. By 2026, we expect a little over 2,000 megawatts online, growing to just over 2,500 megawatts by 2030. Roughly 70 percent of the capacity is in the non-residential sector and about 30 percent in the residential sector.

Next slide, please.

Here we show the net effect of, again, applying our assumptions to translate capacity to sales. By 2026, we expect just a little over 5,500 gigawatt hours of sales and growing to just over 8,000 gigawatt hours by 2030. Roughly three quarters of the sales is in the non-residential sector and about a quarter in the residential sector. And as a way of reference, by 2030 the increase is about nine percent of SCE's 2024 reported sales. So again, this is a fair amount of load expected to come online fairly quickly.

Next slide, please.

And in this slide, we show the capacity of projects in SDG&E's territory. By 2026, we're roughly expecting 25 megawatts online, growing to about just over 300 megawatts by 2030. A little over 80 percent of the capacity is in the non-residential sector and just under 20 percent in the residential sector.

Next slide.

And here we show the -- how we -- the impact of translating the capacity to sales. Roughly, we expect about 80 gigawatt hours of sales in 2026, increasing to about 800 gigawatt hours by 2030. Just over 80 percent of the sales in the non-residential sector and just under 20 percent in the residential sector. As a reference, by 2030 the increase is about five percent of SDG&E's 2024 reported sales.

Next slide, please.

This slide shows the impact of the known loads at the statewide level, comparing our planning and local reliability scenarios. The blue line on the bottom is the planning scenario. The orange line is the local reliability scenario. And the green line is the local reliability scenario with the impact of known loads included.

In 2026, sales in the local reliability scenario with known loads is about seven percent higher than the planning and the local reliability scenario without considering the impact of known loads. By 2030, sales in the local reliability scenario with known loads is about 10 percent higher than the planning scenario and 8 percent higher than the local reliability scenario without considering the impact of known loads. And this trend stays throughout the forecast period.

Next slide, please.

Here, I'd like to kind of go over our next steps. We do have an interest in refreshing our data. This data, the known loads data set we have, comes to us as current as of May. And we do want to try to update that. Based on our last experience working with utilities, it was a pretty manual process compiling some of this data, especially extra data fields that we had requested that's not part of the overall known loads data set. And so we want to work with utilities to try streamline the data collection process going forward.

And then we are interested in studying the, you know, how these projects can get completed and if they're sticking to the energization dates that were requested, given the magnitude that we were sort of anticipating to see over the forecast horizon.

And other areas of work left to do, we do want to allocate the impacts to different LSCs. We do want to continue our AMI analysis, especially for Edison and for SDG&E.

Another area we are looking to explore is to have a better understanding of the new pending loads data set that's going to be included in future distribution planning cycles. We would like to explore using this data set in future epicycles, especially to inform our scenario analysis.

Lastly, we have initiated a project with our consultant Itron (phonetic) to explore options on how we can bridge our system forecast to best for distribution system planning. This work has only recently started, so I don't have any anything needed to share as of now, but we may have more information to share in a future DAWG or IEPR workshop. We're starting this project by briefing the Itron team with our overall forecasting approach, and then we hope to engage our stakeholders to get their input. So we do plan to reach out to CPUC, CAISO, and the utility distribution planning staff as always next year. Again, the goal of this project is to develop an approach to extend our system level forecast to better support distribution system planning.

I believe that's the end of my slide, and I'll take any questions.

COMMISSIONER MCALLISTER: Thanks a lot. Great. Thanks a lot, Asish. Really appreciate that. And just, you know, maybe a little bit of context. I think you laid it out properly but, you know, really well. And to the previous panel question about sort of, you know, the speculative -- sorry, is it fair to say it's more speculative? I think this is one example of, you know, the agencies working together to identify an area that they want to drill into more and really sort of surface potential issues that may come up, you know, over and above the kind of baseline forecast and just make sure we're paying attention to all the corners of demand that, you know, that we have to that add up to the managed forecast.

So, you know, kudos to the team for really rolling up your sleeves and digging into that and figuring out what loads we know and, you know, whether their loads may or may not and trying to sort of give a handicap, you know, probability and assess sort of the likelihood of different loads developing. So appreciate that. I got a briefing really recently on this, so I will not ask any more questions.

But wanted to just invite Commissioner Douglas. I think Commissioner Houck had to step out. I'm not sure if anyone else has joined us.

And Raja, just confirming that Vice Chair Gunda has not joined us.

MR. RAMESH: Yeah, correct.

COMMISSIONER MCALLISTER: Okay, great. All right. Well, terrific.

Anne, did you want to step in and do -- if there are any other questions in the Q&A and get those addressed before we break?

MS. FISHER: Sure. Yeah. Thanks, Commissioner.

All right, we have a few questions in the Q&A.

First question.

"On slide four, do you all have any idea why PG&E's utilization factor for commercial and industrial is so much lower than the other IOUs?"

MR. GAUTAM: Yeah. So as I mentioned, for PG&E,

we looked at completed projects from their known loads dataset and looked at their meter data to look at how their peak demand, monthly peak demand varied relative to the capacity requested. And so what we've seen the actual meter data is the actual utilization to be much lower.

For SCE and SDG&E, we weren't able to do a similar analysis. And so we are relying on the capacity that's reported in their known loads data. So it is an issue, but, you know, we considered maybe applying a uniform factor. But at this point, we decided to hold off on that. You know, customers, they can be very different from each other, especially if we have different utilities and different customer classes and whatnot.

So for future, we do want to try to refine how we develop those factors and extend that to Edison and to SDG&E by actually collecting the underlying AMI data to do a similar analysis that we did for PG&E.

MS. FISHER: Yeah. Thanks, Asish.

Next question.

"Do your slides 6 through 11 just show the known loads that exceed your baseline or the total known loads? Do you expect the delta between the known loads and your baseline to increase over time?"

MR. GAUTAM: Yeah, so in slides 6 to 11, I'm just showing the extent of the known loads that exceed our baseline forecast.

As far as the delta increasing, so if we update our known loads dataset and there's been more customer requests for projects, then, yeah, so then yes, the delta will grow over time. But right now, we're using the May version of the known loads dataset that we received from the utilities.

MS. FISHER: Yeah. Thank you.

Next question.

"Similar to Katie's question on slide 4, you mentioned a desire to refine the SCE and SDG&E utilization factors. Do you think any -- or do you have any specifics you could share about how you're thinking that may be done?"

MR. GAUTAM: Yeah. So again, the way we did it for PG&E was to take a look at the completed projects and look at how their maximum demand varied relative to capacity to derive a utilization factor and replicate that same analysis for SCE and SDG&E.

MS. FISHER: Thanks.

Next question. "I'd like to hear about how the load modifiers will be distributed for use to PG&E." I'm not sure if maybe they're talking about the known loads.

MR. GAUTAM: So one of the things we're exploring is for every IEPR cycle, for different load modifiers, we do a load bus allocation. And so we're considering doing something similar with the known loads impacts, and we can try to make that available to PG&E.

MS. FISHER: Great. And Mark is asking about asking this question live. So unfortunately, right now, we're only addressing questions in the Q&A. So if you wanted to put more additional context, we can address that. Otherwise, there is a chance to speak at the end of the workshop to include a public comment or, you know, I think as we've discussed, you know, you can also follow up with us after this workshop. We're happy to chat with you about it.

COMMISSIONER MCALLISTER: Also, maybe Heather or Anne, can you give folks the information before we break for lunch maybe about how they can submit public comment -- or comment, written comment to the docket and all that good stuff and what the deadline is for that?

MS. RAITT: Sure. Yeah. So this is Heather.

Yes, written comments are always welcome. And the notice provides instructions for how to do that. And I believe they are due on November 26 by 5:00 p.m.

MS. FISHER: Yeah. Thanks, Heather.

Next question. "Can you share any information as to the timeline for your project with Itron to better support distribution planning?"

MR. GAUTAM: Sure. As I mentioned in my presentation, we just kicked off this project right now. Itron is meeting with staff internally to have a better understanding of our overall system level forecast process. And then we hope to reach to the staff at the PUC, CAISO, and then also the utilities to better understand other needs. And then Itron will be taking a look at how, based on all the input they receive, on what options there are to better align our system forecast to something that can support distribution planning.

I think a lot of stakeholders, for the next few months we'll be spending more time on these stakeholder engagements. And then towards, I think towards the later part of next year, we'll have some kind of a proposal from Itron to consider. And we'll be happy to share that in a future DAWG IEPR workshop.

MS. FISHER: Yeah. Thanks, Asish.

That's the last question that I see in our Q&A, so I'll hand it over to Heather.

MS. RAITT: Thank you, Anne. Thank you to all presenters.

And I think I might have said November 25th. Anyway, the comments are due November 26th at 5:00 p.m. And as I mentioned, if you wanted to submit written comments, the notice we'll give you all that information.

And they’re due November 26th.

So with that, thank you everybody for joining. And we will be back at 1:30. I will keep this line open, but we’ll just stop recording over the break. So we’ll be back at 1.30 for afternoon presentations. Thank you very much.

(Off the record at 12:01 p.m.)

(On the record at 1:30 p.m.)

MS. RAITT: So I am returning this afternoon. I’m Heather Raitt, the Acting Director of the IEPR Team. And just a reminder that this workshop is being recorded as part of the 2025 IEPR proceeding.

This afternoon, we will follow the same pattern that we had this morning. We will have presentations from the Commission staff, and then a few minutes after to take a panel to take questions from attendees for the Q&A feature on Zoom. And then at the end of the day, we will have an opportunity for public comments, a maximum of three minutes and one person per organization, please.

And then also written comments are welcome and they are due on November 26th. And all the materials for this workshop are posted, including the notice that gives you instructions for how to submit those comments.

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

COMMISSIONER MCALLISTER: Great. Well, thanks Heather.

MS. RAITT: Thank you.

COMMISSIONER MCALLISTER: Just I don’t need to repeat anything I said this morning.

I did just want to acknowledge Commissioner John Reynolds from the PUC. Thanks for joining us this afternoon. Really appreciate that. And wanted to give you a chance to make any sort of initial comments for the afternoon sessions if you’d like.

COMMISSIONER REYNOLDS: Thank you, Commissioner McAllister. I’ll just briefly offer my thanks to all the CEC staff who have put together this workshop. Thank you to the CEC for hosting and inviting us at the PUC. Obviously, the IEPR is a very important component of California’s overall energy policy plan, and I look forward to learning some more this afternoon as we dive further into energy efficiency and fuel substitution and data centers. I think there will be some very interesting topics.

I will have to step in and out as the afternoon goes along for some other meetings, but I’m really looking forward to hearing some more.

COMMISSIONER MCALLISTER: All right. Well, understood. And thanks for joining us to the extent you can. Really appreciate that. Unfortunately, it looks like I’ll have to miss the data center’s presentation or at least part of it, but I think there’s just a lot of real great work going on trying to figure that out and understand that load and what is likely to appear and what isn’t, so really critical to know for all of us.

So with that, I think we are expecting Vice Chair Gunda at some point during the course of the afternoon sessions, but he will announce himself when he joins.

And yeah, with that, pass it straight over to Quentin. Thanks for kicking us off.

MR. GEE: Great. Thank you, Commissioner McAllister. Welcome, Commissioner Reynolds and everyone else back to the workshop on load modifiers and demand loads. For those of you that are arriving fresh this afternoon, just I’ll give you some broad context on the IEPR Forecast.

The IEPR Forecast involves significant interagency collaboration and public input, with this workshop being a useful step in the forecast development. This year’s forecast expands the range of load modifier scenarios, including -- or offering a sort of a broader view of potential futures that are out there.

While all the scenarios are usually adopted by the CEC, specific combinations are selected to guide planning efforts. Namely, the planning scenario is used in resource adequacy and other resource procurement, where the local reliability scenario is used for local transmission studies and distribution planning. This dual scenario approach enables planners to address distinct needs, such as overall energy demand versus grid capacity, sort of capturing that range of uncertainty that exists in the current economic -- the current economic and policy landscape, while ensuring consistency with California's decarbonization objectives.

We are particularly interested in stakeholder feedback on the various load modifier scenarios to be considered for the two main scenarios, that planning and local reliability scenarios that I discussed, keeping in mind the sort of distinct objectives of each.

With that, I'll hand off to Ingrid Neumann. Ingrid and her colleague Ethan Cooper are going to discuss Additional Achievable energy efficiency and fuel substitution load modifiers.

Ingrid?

MS. NEUMANN: Hello. Can you hear me?

MR. GEE: Loud and clear.

MS. NEUMANN: Excellent. All right. Good afternoon, Commissioners and stakeholders. I'm Ingrid Neumann, Decarbonization Principal in the Advanced

Electrification Analysis Branch. My colleague Ethan and I will present on our combined AAEE and AAFS load modifier draft results for 2025.

Let's move forward in the slide deck. And one more. And one more. Great.

So here we have a couple of slides, so two slides, of handy acronyms, initialisms, and abbreviations which are employed in our slide deck.

Next slide. Next slide.

This is our agenda for today's presentation. I will start out with a little background information on the Energy Commission's Additional Achievable framework and then dive into the program and incremental codes and standards portion of our work. Ethan will continue by describing the zero-emissions appliance adoption scenarios and summarize how the components are combined to create the aggregate AAEE and AAFS load modifier combinations. Finally, he will show how our load modifiers are ultimately expected to affect the baseline electric and gas consumption forecasts.

Next slide.

The Additional Achievable framework is applied to energy efficiency, fuel substitution, and as you saw this morning, transportation electrification for the IEPR Demand Forecast. It has existed formally for AAEE since 2015 and

AAFS since 2021.

As before, our Additional Achievable scenarios capture a range of incremental market potential impacts beyond what is included in the baseline Demand Forecast but within the range of what is reasonably expected to occur. The scenarios range across a spectrum from conservative, here on the left in red, to optimistic on the right in violet. Scenario 3 is designed to be a business-as-usual or best view of what the future might look like when considering current available data within the existing policy landscape, while the other scenarios can be viewed as lower and upper bounds to these expectations.

Next slide.

As we have added components and complexity to our building load modifiers, we found it necessary to introduce some new nomenclature to fully explain our AAEE-AAFS paradigm. Programs and incremental codes and standards are abbreviated as PiCS. They capture IOU and POU programs, as well as all of the other programs outside of those designations, which we group and refer to as beyond-utility or BU. PiCS also include the incremental impacts from buildings and appliance standards. PiCS are the only contribution to AAEE, while AAFS has two pieces, one being PiCS and the other being zero-emission appliance adoption scenarios, which capture local impacts from air quality management district efforts or statewide impacts from CARB’s Scoping Plan or State Implementation Plan.

Now looking at our table here on the slide, PiCS AAEE are modeled within about 45 separate workbooks, one for each program in incremental code and standard type, and are then aggregated and integrated for each scenario on an annual basis using an R script. AAEE has been developed in this format since 2019 and is represented in the first row of this table.

A similar approach is used for the PiCS AAFS in the second row and has been developed in this format since 2021. Hourly results for both PiCS components are generated using an R-based hourly tool, which applies sector and use-based load shapes to the annual PiCS load modifiers.

Zero-emissions AAFS shown in the third row utilizes an R-based technology replacement model called FSSAT. which we first developed in 2020 to support AB 3232 policy analysis.

The final AAEE and AAFS load modifier is composed of a combination of scenarios from the three aforementioned components, which are aggregated in additional modules for both annual and hourly results. This combination of building load modifiers has been part of our IEPR Forecast since 2023.

I will now transition to focus on the PiCS discussion. Afterwards, my colleague Ethan will focus on the zero-emission appliance standards piece and how all three pieces, PiCS AAEE, PiCS AAFS, and zero-emissions AAFS combine into our final total IEPR AAEE-AAFS load modifier scenarios.

Next slide, please.

So we're making that transition; all about PiCS. Excellent. So the PiCS AAEE and PiCS AAFS are refreshed every two years, and there were a few significant updates listed here for 2025.

We received a new CMUA potential study, as expected, every four years, which for the first time included electrification potentials for the POUs. The IOU potential and goals study, which we leveraged for IOU program potential, was also updated. This is on a two-year cycle coinciding with our PiCS updates.

Then AB 130 paused the California Title 24 Residential Building Standards for the 2028 cycle, but does not affect non-residential construction. What this means is that the residential standards will be held at the 2025 level through the 2028 cycle and have the opportunity for improvement again in 2031. Non-residential standards will be updated as usual in 2028 and again in 2031 and so on.

We also improved our modeling of both appliance and building standards past 2030 to ensure minimum impacts were retained even when new standards had not yet been proposed. Title 24 impacts show higher levels of electrified new construction versus what was assumed in 2023. This is based on data collected over the past two years.

We were able to model new future standards, including federal appliance standards. There was some concern earlier this year about existing standards being rescinded, but that has not occurred. IRA funding is being eliminated this year and this did affect cost-effectiveness of electrification measures in the IOU portfolios.

While equitable building decarbonization programs were affected by the California budget adjustments, they are now fully scoped or existing firm programs and thus were incorporated across all scenarios.

Next slide please.

This slide serves to remind us of the various types of elements that are quantified in PiCS AAEE. It's a summary, not an exhaustive list, but the savings for the first grouping increase by scenario from one through six and are included in each scenario. Those include the IOU and POU energy efficiency programs, the Title 20 and Federal Appliance Standards, as well as the Title 204 California Building Standards.

There are various new appliance standard measures modeled this cycle that start having significant first-year savings in 2026 and 2027. They include Federal Appliance Standards for air compressors, pool pumps, microwave ovens, refrigerated vending machines, and single-package vertical AC and heat pumps. Also on the Title 20 side, there is an expanded scope for general service lamps and energy conservation standards for consumer clothes dryers with impacts starting in 2028. We also included commercial dishwashers and fryers in future Title 20 standards. Both are currently still at the RFP stage but are being pursued by the energy commissions. First-year savings for those standards would be expected in 2030.

Then in the second and the third grouping, other programs are only included in a conservative view in the business-as-usual scenario and to higher levels in more optimistic scenarios.

Next slide, please.

This is the spectrum of the draft PiCS AAEE Scenarios 1 through 6 for 2025. Electricity savings are shown on the left and gas savings on the right. There is the uncertainty is shown by the bounds from one through six, but the focus on business-as-usual and for planning has historically around AAEE 3 and the more conservative view of that in AAEE 2 or the more optimistic view of the business-as-usual scenario in AAEE 4.

Next slide, please.

Here we're showing the four major groupings and their contributions to PiCS AAEE Scenario 3 in 2025 on the left and 2023 on the right. Scenario 3 is chosen here because it's our business-as-usual scenario and has traditionally in the past been utilized for statewide planning. As you can see, savings are larger, reflecting more savings from incremental codes and standards.

More future new appliance standard measures are modeled and included in Scenario 3 in 2025 than were modeled and included in Scenario 3 in 2023. We also improved our modeling parameters this cycle to preserve the impacts from Title 24 post-2030.

POU programs, however, show an increased focus on energy efficiency versus fuel substitution. The opposite had been foreshadowed in the 2021 CMUA Report, we get that every four years, on POU Energy Efficiency Potential, which saw energy efficiency savings diminishing and did not yet quantify fuel substitution. POU fuel substitution potential was limited to preliminary data from a small subset of POUs willing to share it with the Energy Commission in 2021 when we first introduced AAFS and may have been optimistic and not reflective of the majority of California's POUs.

The remainder of the programs, which we bundle here as beyond-utility, show a focus on fuel substitution rather than energy efficiency, so those savings are smaller. Those programs had been scoped to be able to include both energy efficiency savings and fuel substitution impacts, but obtained data shows that the focus is on the latter rather than the former.

Next slide, please.

This slide shows a similar comparison of the more conservative AAEE 2 scenario between 2025 and 2023. Traditionally, this scenario had been used for local planning efforts. The trends by bundle remain the same as before and, as expected, the savings are slightly less.

Next slide, please.

Now we transition to the PiCS AAFS scenarios, and we can see that there are various types of elements quantified in PiCS AAFS as there were in PiCS AAEE. It's again a summary and not exhaustive. The impacts for the first group do increase by scenario from one through six, but everything in that first group is included in each scenario, so those are IOU and POU fuel substitution programs, the Energy Commission's BUILD Program, IRA Pay for Performance and HHERA, the components of the building standards that encourage all or partial electric new construction and additions and alterations, the TECH

Program, our own Equitable Building Decarbonization Program, or programs plural, and California Electric Homes program.

Other programs in the second and the third bubble are only included in a conservative view in the business-as-usual scenario and to higher levels in more optimistic scenarios. Programs previously retained only in some of the more optimistic scenarios are now captured across the bulk of the scenarios because they are fully scoped, funded, and/or have started making awards.

For 2025, we were able to leverage existing program data to better split energy efficiency and fuel substitution impacts for programs that could be employed for both. Data collected established that fuel substitution was the predominant choice by program participants.

Next slide.

This is the resultant spectrum of the draft PiCS AAFS Scenarios 1 through 6 for 2025. The gas savings are shown on the left and the resultant incremental electricity additions are shown on the right. So, for example, if a furnace is removed, that gas consumption is displaced. The heat pump that is replacing that furnace then does have an incremental amount of electricity consumption and that’s what we’re showing on the right.

Next slide.

Here we're showing the four major groupings again and their contributions to PiCS AAFS Scenario 3 in 2025 on the left and comparing that to 2023 on the right. Again, Scenario 3 is our business-as-usual scenario and had been used traditionally for utilized for statewide planning.

Increases in PiCS AAFS 3 this year with respect to 2023 are due to improved modeling preserving the impacts from Title 24 post 2030 and the fact that established electrification impacts in new construction for the past two years have been greater than what we originally assumed them to be in 2023.

Improved data on existing beyond-utility programs also yielded in greater fuel substitution impacts than energy efficiency and these impacts are more firm so more programs were included in the AAFS 3 PiCS component.

Next slide.

This slide shows a similar comparison of the more aggressive AAFS 4 scenario between 2025 and 2023. Since the introduction of AAFS in 2021, this scenario was utilized for local electricity planning efforts. The trends by bundle again remain the same and the impacts as expected are slightly greater in the more aggressive Scenario 4 than in Scenario 3.

And next slide please.

Here we have a similar comparison of the more conservative AAFS 2 scenario. The trends by bundle are the same as before and the impacts as expected are slightly less in Scenario 2 than in Scenario 3.

Next slide please.

This is a table summarizing the notable changes presented in the previous slides, the most important of which I already highlighted as we covered the draft results and will summarize once again here.

So in the first row we saw increased savings and impacts from codes and standards for both PiCS AAEE and PiCS AAFS. That is due to modeling new or more new future appliance standards in 2025 than we had data and capability to do in 2023. We also improved our modeling to preserve the impacts from Title 24 post-2030.

Then in the second row we saw increased 2025 PiCS AAFS impacts in most cases relative to 2023. There are greater assumed Title 24 electrification impacts in 2025 based on the last two years of data on all-electric or partial-electric new construction and additions and alterations. We also had improved data on existing beyond-utility programs to show that greater fuel substitution impacts are observed than energy efficiency for both for programs that can address both and beyond-utility programs with existing impacts are included in more scenarios.

The third row, lower PiCS AAFS potential from POU programs, so that's one item that did go down a significant amount. That is because the POU impacts this cycle are based on the actual 2025 CMUA potential study rather than a scattering of data from selected and willingly participating POUs in 2021. That was preliminary data that's also four years old.

Then the 2025 potential study did show prioritization of energy efficiency for the POUs over fuel substitution. So that is one thing that we also saw. So their energy efficiency programs increased while fuel substitution decreased.

In our second to last row, we did see a slight decrease in AAFS -- or PiCS AAFS potential from IOU programs in 2025. That is due to the elimination of IRA incentives, changes to EULs, and incorporation of electrification adders, which altered the cost effectiveness of the fuel substitution measures modeled in the potential and goal study process, which must compete against energy efficiency measures.

Then in the last line, you may have noticed something that is visually odd. There was a crossing of the gas PiCS AAEE 5 and AAEE 6. That is not a novel thing. It's simply because we had some beyond-utility programs included in these aggressive scenarios that have a finite lifetime or potential of energy efficiency savings. And in the most aggressive, Scenario 6, we start those first year savings earlier and exhaust them at a more rapid rate than in Scenario 5. So that shifts the peak savings year earlier in the forecast, making those lines cross.

Next slide, please.

Thank you for your attention and interest. If you could hold your questions until after Ethan completes his portion of the presentation, we would be happy to answer them then.

Without further ado, I would like to then hand off the presentation to my colleague, Ethan Cooper, who will go over the zero-emission appliance adoption scenarios and how the two PiCS components that I’ve described and the zero-emissions AAFS ultimately combine for our total AAEE AAFS load modifier and actually modify baseline gas and electric consumption.

Thank you, Ethan.

MR. COOPER: Thank you, Ingrid. Yeah. Make sure I’m unmuted. All right. Pretty good. So, yeah, good morning -- or good afternoon, everyone. My name is Ethan Cooper. I’m going to present on the draft annual and hourly results for our zero-emission or ZE AAFS scenarios, along with the AAEE and AAFS scenario combinations.

Next slide, please.

So before going into our results, I'm going to provide a bit of background on some of the updates made to our ZE modeling this year. So, one of the first ones is that for our modeling of the Air District's Zero-NOx Appliance Regulations, only the adopted Air District rules are modeled in our scenarios, starting with the Scenario 3, going out to 6, and the South Coast's rejected Rules 1111 and 1121 are going to be removed from all of our scenarios this year.

For the statewide ZE modeling, our Scenario 3 was updated this year to model CARB's Scoping Plan, while Scenario 4 continues to model a concept of CARB's Zero-Emissions Space and Water Heater Standard, but now with a 2030 compliance year. We've also added a new ZE AAFS Scenario 1 for this new IEPR cycle.

We've also updated our energy efficiency weightings used in FSSAT for residential electric water heaters to better reflect upcoming federal energy efficiency standards shown in the third row here, and again, FSSAT is our fuel substitution scenario analysis tool. Other minor updates were also made this year to some of our inputs and data assumptions, with one of note being revisions to our AC penetration rates data that was based on new advanced metering infrastructure, or AMI, analysis.

Next slide, please.

So, for our updated AC penetration rates data, we are showing it geographically below in these heat maps that show the percentages of meters within different building climate zones that have high significant cooling load, with higher loads showing up more in the inland regions of California and a lot less on the coast.

As a quick note, we had no data available this year to update any information for Building Climate Zone 7, kind of the gray area down by San Diego.

This data is used in our FSSAT tool to help us determine the number of homes that currently have air conditioning in them, as added cooling load for our modeling is only calculated for heat pumps that are being installed within buildings, residential buildings, that do not have AC already.

Next slide, please.

So, when developing our AAFS and our AAEE scenario combinations, we created a suite of different combinations that detail how both EE and FS, those two load modifiers, interact and sum together. One major thing I'd like to note about these scenario combinations is that for AAEE, we have our gas savings be dependent on the amount of AAFS electrification that we model in FSSAT. For today's presentation, though, we're going to focus on the three combinations that I have bolded in the table below, with our AAFS 3 plus AAEE 3 traditionally being used for our electricity planning scenario, and the AAFS 4 plus AAEE 2 traditionally being used for our electricity local reliability scenario.

With that, next slide, please.

This table here just kind of goes through the characterization for our AAFS scenarios this year. Looking at the ZE components, so kind of the last, after the second row here in this table, all of our scenarios model gas fuel substitution for residential and commercial space and water heating, but Scenarios 5 and 6 also include cooking and clothes drying. Residential propane substitution is also included, but only within Scenario 6.

Statewide ZE modeling for new construction buildings, so anything that goes beyond what is already included in our PiCS Title 24 impacts, that starts in Scenario 4, as you can see here in the fifth row in the table. For statewide ZE modeling in existing buildings, we have various replace on burnout or ROB adoption curves being used for the different scenarios, which I'll discuss further in the next slide. But before going to there, the last two rows we have here shows we're including the adopted Bay Area and South Coast Air District rules within Scenarios 3 through 6, as I noted a few slides earlier.

Next slide, please.

So, the chart here now shows our replace on burnout or ROB adoption curves, which apply to statewide existing buildings for ZE AAFS. FSSAT distributes the amount of gas that will expire or burn out each year based on assumed effective useful life for appliances. These ROB adoption rates are thus indicating the yearly percentage of burning out gas appliances that will be replaced with a zero-emission alternative, such as a heat pump.

The orange line we have here is used for our Scenario 2, while the blue line is used for our scenario -- excuse me. Orange is for Scenario 1, blue is used for our Scenario 2. The dashed red and gray lines are used for our modeling of the CARB's Scoping Plan in Scenario 3, with different lines for the residential in red or the commercial sector in gray. The line to the far left, the green one, is used for our Scenarios 4 through 6. And again, Scenario 4 just looks at modeling a concept of CARB's Zero-Emission Space and Water Heater Standard, while Scenarios 5 and 6 also go beyond the standard to look at other end uses and fuel types I discussed in the previous table.

Next slide, please.

Moving on to our draft results, the chart here shows the gas savings seen for our six AAFS scenarios, now combining the impacts from both PiCS and ZE AAFS. We still see a clear progression in gas displacement as we move through our six scenarios, going from most conservative to most optimistic. And when just focusing on Scenarios 2 through 4, we see that Scenario 2 shows the lowest amount of gas savings throughout most -- or all of the forecast period. There's about 3,600 MM therms of savings by 2045 for Scenario 2, which is compared to about 3,900 MM therms for Scenario 3, and about 4,300 MM therms for Scenario 4.

When comparing Scenarios 2 and 4 together on their own, we see a very big difference in gas savings between the middle part of our forecast, which is kind of shown by the second black arrowed lines in the middle of the chart. And this is largely due to the differing ROB adoption rates for these two scenarios that is seen at this time.

Lastly, when looking at the two different vintages of AAFS 3, the solid line is for this year's IEPR scenario, the dashed orange line is for last year's 2024 IEPR update, we see that savings for this scenario are lower for this year's IEPR cycle. This is primarily a result for our characterization updates made to AAFS 3 this year, both for statewide modeling of new construction as well as existing buildings.

Next slide, please.

The chart below now shows the gas displacement seen for the combination of our AAFS 2 plus AAEE 3. Baseline gas demand for the residential and commercial sectors is shown by the dashed gray line on the top, and the three transparent colored wedges shows the load reduction seen by our different load modifiers. Our ZE AAFS displacement is shown last in the reduction order, as these savings are more uncertain than what is included in our PiCS modeling.

By 2045, our load modifiers reduced baseline gas consumption by about 68 percent, leaving us now with around 1860 MM therms of baseline gas demand remaining. Most of the baseline gas reduction from this combination and from the other ones we're going to see in the next few slides comes from the ZE AAFS component, which is the orange wedge.

Next slide, please.

All right, now for the baseline gas consumption under the AAFS 3 plus AAEE 3 combination, gas reduction happens faster and earlier than seen in the previous chart. By 2045, our modifiers will reduce the baseline gas consumption by about 72 percent, which leaves us with about 1,630 MM therms of gas demand remaining.

Next slide, please.

Finally, for the baseline gas consumption under the AAFS 4 plus AAEE 2 combination, the baseline gas reduction occurs at a similar yet slightly more aggressive rate than in the previous slide. By 2045, our load modifiers reduce baseline gas consumption by about 78 percent, which leaves us with now around 1,280 MM therms of baseline gas demand remaining.

Next slide, please.

Moving on to our electric impacts for the six scenarios, we again see a gradual increase in added gigawatt-hour impacts as we move through each scenario, most conservative on Scenario 1 to more optimistic in Scenario 6.

For the added electric impacts in 2045, we see almost 35,000 gigawatt-hours of added electricity for Scenario 2, close to 40,000 gigawatt-hours for Scenario 3, and about 43,000 gigawatt-hours for Scenario 4. These electric impacts are also displaying a very large gap between Scenarios 2 and 4 during the middle part of the forecast, which, similar to the gas side, does begin to shrink as we get to the tail end of our forecast period in 2045.

Finally, when comparing our two IEPR vintages for Scenario 3, we see that the electric impacts are going to again be lower for this IEPR scenario -- or for Scenario 3 in this year's IEPR forecast. Along with the reasons I discussed for the gas displacement chart, the lower AAFS 3 savings for this year's IEPR -- excuse me, lower AAFS 3 added electricity impacts, are being driven by our updated efficiency weightings we have for residential electric water heaters, which this year is putting a lot more priority on installing more efficient heat pump water heaters over electric resistance in our modeling.

Next slide, please.

So, the chart on this and the following few slides are going to show the combined electric impacts for AAEE and AAFS scenario combinations. For AAFS 2 plus AAEE 3, the black net impact line shows that we're having overall savings throughout most of the forecast period. By 2041, the scenario combination is going to start adding more electricity than it saves, with the net impact in 2045 being around 5,800 gigawatt-hours of added electricity. Most of the added load seen for this combination, and for the other two we're going to see later, comes from the ZE AAFS component, which is the orange bar on this graph.

Next slide, please. Thank you.

So, for the electric impacts of the AAFS 3 plus AAEE 3 combination, the net impact is positive much earlier than what was seen when using AAFS 2. This scenario combination will start adding more electricity than it saves starting in 2031, with the net impact in 2045 being around 10,800 gigawatt-hours of added electricity. Given that we're using the same AAEE scenario here for this combination, the net impact increase is coming solely from more added electricity seen with AAFS Scenario 3.

Next slide, please.

Finally, for our electric impacts of the AAFS 4 plus AAEE 2 combination, the net impact is positive even earlier than in the previous slide. This scenario combination will be adding more electricity than it saves starting in 2029, with the net impact in 2045 being around 18,200 gigawatt-hours of added electricity. The increase we see in the net impact here comes both from the increase in added electricity for AAFS 4, along with the decrease in electricity savings seen when using AAEE 2 rather than AAEE 3.

Next slide, please.

Taking a look now at our average hourly profile for our select EE and FS scenario combinations, the first chart below details the impact seen on a winter day in February. The results on this and the following few slides are for the CAISO system impacts, so looking at PG&E, SCE, and SDG&E. For February, all scenario combinations show an increase in megawatt demand during most of the day, with a slight decrease or reduction being seen during the early to late afternoon time period. The large peak that we see during the early morning time comes from added space heating and water heating demand from our AAFS scenarios, and the peak later in the day is also coming from both space and water heating as well.

Next slide, please.

Splitting up our AAFS 3 and AAEE 3 impacts into the added fuel sub impacts in orange and the reduced energy efficiency impacts in blue, the black net impact line from the previous chart shows that the highest amount of megawatt load, around 9,400 megawatts, would show up at hour ending eight. The load increase at this hour for AAFS 3 is going to be more than four times the load decrease seen from AAEE 3, showing just how much of an impact AAFS has in the morning time for February on adding load compared to what gets reduced from AAEE.

Next slide, please.

We're now looking at the average hourly profile for September in the summertime. We see a very different shape from what was observed in February. There's again added megawatt load happening during the early morning time, but at a significantly smaller scale than what was seen in February, and now being only driven by added water heating demand in our AAFS scenarios. The larger peak will actually be during the late afternoon to early evening time period, so kind of hours 15 to 19, and this is largely being driven by both added residential cooling demand from

AAFS and, to a lesser extent, added water heating demand from AAFS as well.

Next slide, please.

Looking more closely at the average September hourly profile for AAFS 3 plus AAEE 3, the black net impact line now shows that the highest amount of megawatt load would be at hour ending 19, and that would be about 2,500 megawatts of load being added at that time. The load increase at this hour from AAFS 3 is now less than two times the load decrease seen from AAEE 3. So, the difference between AAFS and EE in the summertime at the maximum hour here is going to be a lot less than what was seen in the February winter time frame.

Next slide, please.

I'm going to now move into our electric appliance stock projections for our AAFS scenarios, focusing on Scenario 2 and Scenario 3.

Next slide, please.

Before going into our results, I do want to provide a quick update on our CEC's heat pump tracking efforts.

So first, staff currently have an unofficial heat pump count for heat pumps in California, which is an estimate of 1.9 million heat pumps by quarter four 2024, and 2.1 million heat pumps by quarter two 2025. Overall, we’ve seen an increase in agency-wide efforts to track both space and water heating appliances, with a particular focus on heat pumps.

One thing I want to note here is that we’re still planning to be able to leverage AMI data in the future for further help with tracking homes that are installing heat pump technologies. CEC staff are also still in the process of developing a heat pump tracking dashboard, which will provide quarterly updates on heat pump counts in the state and is expected to be coming online by the end of this year.

For this year’s 2025 IEPR analysis, we’re planning to use the quarter four 2024 update -- sorry, estimate of 1.9 million existing heat pumps as a baseline to see how much further we can go in our different AAFS scenarios.

Next slide, please.

All right, moving now into our electric appliance stock projections, the chart below shows a cumulative forecast for AAFS Scenario 2. For this scenario, most of our added residential heat pumps comes from the PiCS AAFS component, which is the orange wedge -- or orange bar on this chart. By 2030, AAFS 2 has a cumulative total of about 5.8 million heat pumps when combining the impacts from both the PiCS, the ZE, and the baseline component in blue, so the green, orange, and blue bars. We also see an additional 300,000 electric resistance water heaters are being added by ZE AAFS by 2030, which, had they been heat pumps instead, would have actually pushed our scenario over 6 million cumulative heat pumps by 2030.

Next slide, please. Thank you.

So, for AAFS 3, there's a significant jump in the added residential heat pumps for the AAFS component, particularly when looking at ZE AAFS in green. PiCS AAFS still plays a major role in added heat pumps up until 2030, which is where ZE AAFS actually adds just about 0.1 million more heat pumps than the PiCS does.

Overall, Scenario 3 is well above 6 million cumulative heat pumps by 2029, and by 2030 has added around 8.8 million total heat pumps. ZE AAFS 3 is also adding about 700,000 electric resistance water heaters by the year 2030, which, had they been heat pumps instead, would have actually had our Scenario 3 be around 9.8 -- sorry, excuse me, 9.5 million total heat pumps by that year.

All right, next slide, please.

That's the end of my presentation. Thank you all, and I'm going to pass it on to Commissioners and the Dias for questions.

COMMISSIONER MCALLISTER: Thanks so much. That was great. Ingrid and Ethan both did a nice job. A lot of very dense presentations, visually exciting and dense. So I just want to say thanks for all the hard work, obviously, that went into that.

I've gotten relatively frequent briefings on this, so I'm feeling relatively informed. I guess maybe I would just comment by way of providing a little context that we are entering this, you know, we're solidly in, actually, this new world where we're trying to, you know, electrify very intentionally, and heat pumps are the tool for getting, you know, much of our building stock decarbonized as we leverage the backbone of a clean electric system.

And so market transformation, as I think we all know, is a tricky and kind of more of an art, really, than a science. And so, you know, you have a tough task here, which is trying to figure out even what's the baseline, and then what is going to really drive adoption. And, you know, the bookends on adoption are very, very wide; right?

And so I think it really just points to the fact that we need to continue to work together across the agencies, across the state, with the Governor's Office, their goals, with industry and the heat pump partnership, and just all of the tools in our toolbox, and just develop those and keep them sharp to do everything we can to really grow the various sectors within the heat pump marketplace, and at the same time, not lose sight of the implications for the grid, and do everything we can to make sure that all of these new loads are good citizens on the grid and, you know, that that load is falling in a place that is most easily accommodated by the grid, and that we can therefore be intentional about investments in the grid infrastructure, and be judicious about that.

So lots of different, you know, boxes to check along the way, and so it’s really just going to take continued collaboration.

I did have one question. I thought, I think it was, Ethan, that I think you said that in one of the FS scenarios, AC was driving a peak increase, and I was a little confused by that, because generally, AC is going to be replacing the existing, less efficient AC, and so the AC itself ought to be not driving the peaks.

MR. COOPER: Yeah.

COMMISSIONER MCALLISTER: The heating may be driving a winter peak, right, the heating component of the heat pump.

MR. COOPER: Yeah, I bet I misspoke there. I think I was trying to mean that added cooling load for any building that never had AC to start with.

COMMISSIONER MCALLISTER: Oh, got it.

MR. COOPER: That type of cooling load. I meant to say that instead of just AC load, because the tool does account for who has an AC, and if you already do, don't account for -- don't calculate added cooling load --

COMMISSIONER MCALLISTER: Yeah.

MR. COOPER: -- for that heat pump, because it's probably lower electricity usage than when they had their old AC unit.

COMMISSIONER MCALLISTER: Okay, got it.

MR. COOPER: Yeah.

COMMISSIONER MCALLISTER: So basically, somebody's replacing a furnace with a heat pump and it's coming along with AC, and therefore it's a new AC load?

MR. COOPER: Yeah, basically, yeah.

COMMISSIONER MCALLISTER: Okay, got it. Got it. Okay, thanks for clarifying that. I appreciate it.

MR. COOPER: Yeah.

COMMISSIONER MCALLISTER: I don't know, Commissioner Reynolds or Raja? I'm not sure if Vice Chair Gooden has joined us yet. Commissioner Reynolds, I'm not sure, you may have had to step away. I think he said he might have to be in and out.

COMMISSIONER REYNOLDS: I'm in transit at the moment. Hello.

COMMISSIONER MCALLISTER: Hey, there you are. Okay. No worries at all.

COMMISSIONER REYNOLDS: Hopefully --

COMMISSIONER MCALLISTER: It was a dense presentation. I can only imagine while you were driving, trying to take it in.

COMMISSIONER REYNOLDS: And I definitely echo your remarks about continuing the collaboration to drive heat pump adoption. And I don't think I have any particular questions at the moment, but I do really appreciate the presentation and all the work that's behind it.

COMMISSIONER MCALLISTER: Thanks for being with us. I really appreciate your -- and we can follow up, and the presentations are all posted. And if you have any questions, obviously, staff is happy to answer those.

I just wanted to point out the TECH Program, which I think has been a very interesting market transformation effort, TechLink (phonetic) California. And we've actually -- so the Energy Commission with some of the federal HERA money has been piggybacking and sort of juicing up the low-income portion of TechLink California, you know, using that infrastructure that the PUC put into place. And that's been really, I think, a great way to get some relatively quick action in growing the heat pump marketplace. And we're trying to now figure out sort of what the next phase of HERA looks like. And we may end up continuing to leverage something like that program design for the rest of the HERA money. We have to kind of see. Now that the government's open, maybe we can get some clarity.

And honestly, our DOE counterparts have actually been quite relative to some of the expectations we might have have had with the shutdown and just the transition in the general policy direction in D.C., I think DOE, certainly the compliance staff at DOE have been actually quite good, so I want to acknowledge them as well.

Oh, Commissioner Houck, hey. Yeah, chime -- go ahead and chime in. The mic's yours.

COMMISSIONER HOUCK: Yeah, I just wanted to say that I really appreciated the presentation. I know we're doing a lot of collaborative work with the building decarbonization proceeding, our EE proceeding. We have our market transformation initiative. And just being able to coordinate on what this is going to mean for meeting our goals is really important. And I know we just issued a decision not that long ago in building decarb to start looking at how we can have more flexible engagement with the grid to be able to allow some of these technologies to get into place, even if we're still working on longer-term capacity issues.

So just appreciate the presentation and all the work that's being done in the different programs across agencies.

COMMISSIONER MCALLISTER: Great. Well, thanks for being here. And, you know, this is sort of a snapshot in a much -- in a long collaboration, so no doubt lots to come.

Let's see, any, do we have any Q&A from attendees? I think Jesse Gage was going to step in to moderate that.

Hey, Jesse.

MR. GAGE: Thank you. Thank you. As it happens, we do not have any Q&A at this time.

COMMISSIONER MCALLISTER: We do not?

MR. GAGE: So I suppose I could just hand it right back to Mathew, over to Mathew Cooper to take us home with data centers.

COMMISSIONER MCALLISTER: Great. And just a heads up, Mathew, I'm going to have to step out mid-presentation, so apologies, but I've got a 2:30 hard stop. But, yeah, obviously I'm in capable hands with the IEPR team.

And Raja, please do take over.

MR. COOPER: Great. Thanks.

COMMISSIONER MCALLISTER: All right. Thanks, everybody.

MR. COOPER: Okay, so I'm going to present our preliminary data forecast, Data Center Forecast for 2025. This is similar to what we presented at the DAWG and elsewhere, but we do have a slight update to the results.

So next slide.

Our methodology is similar to what we've developed for the 2024 IEPR. We're again, relying on the applications for service, which data center developers submit to utilities. So we requested lists of those projects from any utilities that are expecting data center growth, so that we have the total capacity in megawatts that's being requested, as well as the status of the application and a ramping schedule, or at least a year in which they would start service.

We then apply some assumptions for utilization factor, confidence level, and in some cases, our own ramping assumptions to create a forecast of maximum demand out of those requested capacity numbers.

This year, we're using the same utilization factor as last cycle, 67 percent, which is based on some experience that Silicon Valley Power, the utility, shared with us. They have a lot of data centers in their territory.

We're adjusting our confidence levels and ramping assumptions a little bit compared to last year, so I'll have some more slides on that later in the presentation.

And lastly, we've analyzed a sample of metering data to create hourly profiles in order to translate this maximum demand into an hourly forecast, and I'll talk about that at the very end.

Next slide.

So these are the utilities which we received project level data from: PG&E, SCE, SVP, Palo Alto, and VEA. We also had some conversations with these other utilities, San Diego and Burbank, which both described some small potential projects, so we added those to the forecast as well.

Note that last year, San Jose was exploring becoming their own LSE, so we had counted the load separately in last year's forecast, but those plans have been put on hold, so this year, those projects will be grouped with PG&E.

We have talked with SMUD a few times in the past, and based on those previous conversations, we don't expect any new data centers in Sacramento.

So this first data request was in September, and we've asked the utilities in the first list to give us an update by early December just to see if their application queue has changed significantly, so we can try and use the latest data possible before the Demand Forecast is finalized in January. And we'll issue another data request in early 2026 just to get the information we need to do our load bus allocation.

Next slide.

So just a quick note on VEA, which is Valley Electric Association. It's a utility in western Nevada that also covers a small area in California. They're preparing for some large load growth, including data centers. The actual large loads will be in Nevada, not in California, so we won't be including them in our annual Consumption and Sales Forecasts because those are for energy demand in California only, but since VEA is part of CAISO, we will still account for them in the hourly forecasts. So they're included here.

Next slide.

So in our data request, we asked the utilities to give us a status for each project, which informed what confidence level we assigned, basically like probability of completion. And this year, our definitions have changed a little bit as we tried to define the groups consistently across utilities. Last year, we considered Group 1 to be active applications with engineering studies completed or in work, and this year Group 1 consists of projects with signed agreements only. Group 2 previously had active applications which hadn't yet initiated engineering studies. Now our new Group 2 is all projects with an active application. Group 3 is the same as before, inquiries only, which haven't yet filed applications, so those are the most speculative.

So our new Group 1 projects being signed agreements only have more certainty than the previous Group 1 definition. They're basically projects that are moving forward, they're pretty likely to get built. We've heard anecdotally there are still dropouts sometimes. Our new Group 2 is any active applications, which would have been split between Groups 1 and 2 in the previous scheme. So we're also adjusting our confidence levels a bit to reflect this difference in the definitions.

Next slide.

Here's what we received this year. This chart shows the sum of all agreements, applications, and inquiries stacked for each utility, agreements in blue, applications in orange, and inquiries are the hatched green. The total capacity statewide is over 20 gigawatts of requested load, and this is higher than what we received last year, although a lot of it is in Group 2 and Group 3, the more speculative projects.

Next slide.

So here's the new data compared to last year's data just for PG&E and SCE. So for PG&E, some of the applications have moved forward into agreements, and there are some additional applications. SCE has a small amount of Group 1 capacity. There’s a little bit of blue at the bottom of the stack there.

In a previous version of this presentation, we had shown 2025 having less Group 2 capacity, less orange in 2025, but a large increase in Group 3. It turns out after clarifying our definitions with the SCE team, some of those Group 3 projects should have been counted as Group 2. So the total application capacity, the total height of that bar is the same, but because we give Group 2 a higher confidence level, we count more of it in the forecast. So this resulted in our forecast being a little bit higher than what we had previously presented.

Next slide.

So this is just a histogram showing the number of projects bucketed by the requested capacity. Most applications are for 100 megawatts or less due to the small power plant exemption. There are a few larger ones, even some larger ones with signed agreements, and there are a few very large applications also, like in the 500 megawatts or more range.

Next slide.

So for 2025, we’ve tried to develop some confidence levels that we can use consistently across utilities and that reflect our updated group definitions. We're developing three data center scenarios, low, mid, and high, and here on the right are the confidence levels that we're using this year.

For the high scenario, on the far right, we would take 100 percent of the project capacity with signed agreements, that's Group 1, plus 50 percent of the active applications plus 10 percent of the Group 3 inquiries, and that load would be used in our local reliability forecast.

For the mid case, we're taking 70 percent of Group 1 plus 33 percent of Group 2 and zero percent of Group 3, and that will go into our Planning Forecast. And we also have a low scenario with just 50 percent of Group 1, although we don't currently use that for anything.

Yeah, next slide, please.

Our ramping assumptions are also a little different than last year. Both methods were based on information also shared with us by Silicon Valley Power, and this year we're using a linear seven-year ramp rather than the growth rate on the left.

Last year, we only applied the ramping to Group 3 projects that were submitted without a schedule, but this year we dug into the individual projects a little more and applied the ramp to any projects that appeared to come online with a full or a very large load in the first year of request service, because our understanding is that's not realistic. And we also pushed Group 2 and Group 3 projects past 2027 because it's not feasible that they would start service in two years or less if they haven't signed an agreement yet or even submitted an application yet.

So next slide.

So finally, here's the results. This is the mid case maximum demand for the Planning Forecast. Last year's forecast is on the left, the new draft on the right. As I mentioned, in our first draft of the 2025 forecast the statewide total was slightly lower than last year, but since we revised some SCE project groupings to be consistent with our definitions, that's now causing the forecast to be a little bit higher in the long term. It's still slightly lower in the first few years, which is probably due to our updated ramping assumptions.

And overall, it's still fairly similar to last year, even though the total request capacity this year was much higher, like we saw in those previous bar charts. Many of those new projects were Group 3 inquiries, so they don't show up here at all in the mid case. The Planning Forecast is used for resource adequacy and integrated resource planning.

So obviously we acknowledge there's some uncertainty in forecasting data centers. But I just want to note that this mid case forecast especially, we have a high confidence in. It's based primarily on signed agreements, which takes a significant commitment for projects to get to that stage. And the fact that the mid case is pretty similar to last year, even with a different mix of applications, also gives us confidence around the total amount of load statewide. Next slide.

This chart just breaks out PG&E separately, which has the largest amount of load. Just want to point out their forecast did increase in the long run, even though the ramping is slightly slower, so it's a little bit lower in the near term before 2033.

Yeah, next slide.

This is the high case demand, so that goes into the local reliability scenario. This one is higher than last year, again, because we have a significant increase in the total requested capacity, including applications and inquiries. And this scenario counts more of those speculative projects. As the earlier slide said, it includes 50 percent of Group 2 and 10 percent of Group 3.

So the difference between the mid and the high case, which was about 2,000 megawatts by the end of the forecast, kind of shows even if a fraction of these new or less certain projects are completed, the load could be much higher, as we see here.

Next slide.

So we're showing VEA separately. They were not included in the last -- in the result slides just now because we didn't have a forecast for them last year. So the left and right side here are just the mid and high cases. And the data is currently characterizing these as Group 2 coming online starting in 2028, I think, a little bit.

Next slide.

So lastly, I'm just going to mention how this translates to our hourly forecast. We used a sample of metering data from about 50 data centers in PG&E territory to create an hourly profile. And the original data set is actually the same as last year, but this year we calculated monthly profiles in addition to just weekday, weekend profiles.

Next slide.

Here's the hourly load factor compared to last year. The average of all months is kind of almost the same as last year, last year being the dashed line there, and this year being -- this year's average being the orange line. The light blue line is October, which had the highest load factor, and the green is March, which had the lowest. And October demand is higher because it's hotter, so data centers require more cooling than in March. The

October month represented in the AMI data, I think it was from 2023, was a pretty hot October. And we looked at our historical weather for the region also which showed it was above average, so it was actually hotter than September, so that's why October is the maximum here.

But anyways, the profiles are relatively flat over 24 hours, but the monthly difference does show that there is a seasonal component, so weather sensitivity does end up being significant here.

Next slide.

This is the weekend profiles, pretty similar, just a little lower overall compared to the weekdays. So these profiles will apply to the maximum demand to create the hourly forecast for this year, and we're using the same profile for all utilities.

Next steps for the profiles, we would like to expand our dataset to create a more robust sample, explore differences between hyperscale data centers and smaller data center profiles, likely to be some difference there, and possibly develop some kind of regression framework to quantify the weather sensitivity.

Next slide.

I think, yeah, that's it. So we can go to questions from the dais first.

VICE CHAIR GUNDA: Thank you, Mathew. Sorry for joining late today.

Let me see if other Commissioners have any questions. I have the benefit of bugging you all a lot during briefings, so let me see. I see Commissioner Reynolds. And any questions from you both? Don't think we have questions.

Let's move to Q&A first, Mathew.

MR. GAGE: Hi.

"Is the utilization factor provided by Silicon Valley Power at 67 percent overly weighted in favor of transmission-connected data centers, given the footprints of transmission-connected data centers in their service territory?"

MR. COOPER: Good question. Yeah, that seems -- that sounds reasonable. We understood the 67 percent to be the highest number that they had seen, so we sort of conservatively used that. But, yeah, that's an interesting point.

We did discuss this with some of the other utilities, and I think most folks thought that the 67 percent was reasonable, or they had possibly even seen maybe slightly lower numbers than that. But, yeah, definitely would be interested in seeing any numbers that anyone else has on that.

Also, just want to note that the majority of the applications which we have, and I think especially the large ones, are for transmission-connected data centers.

MR. GAGE: Thank you. “Did LADWP provide info on data centers?”

MR. COOPER: We did have conversations with them also. I guess I should have mentioned that. And I don’t think they’re expecting any new load coming online.

MR. GAGE: Thanks.

“In November 2024, PG&E announced a flexible data center pilot. Through this pilot, PG&E will use load control technology to send signals to data centers to reduce their load during grid events. In that same month, PG&E reported that it started three flexible data center pilots and intended to start two more. Do you have any updates on these pilots?”

MR. COOPER: Good question. I don’t, personally. I know load flex is something we’ve been discussing, and that is very interesting. I know, you know, load flex isn’t something we’d include in the forecast. It is something we’re tracking and thinking about, though, obviously. I mean, most, anecdotally, it seems that many data centers are not interested in participating in that. So, yeah, it would be interesting to hear, to keep following that question.

MR. GAGE: “Are you assuming that any new Google data centers will have flexible peak demand load?”

MR. COOPER: We do not. I believe identifying individual customers is confidential information that’s not necessarily shared with us, especially at this stage of the forecast, so I couldn’t speak to any specific, you know, company or customer on their plans. But, yeah, again, we’re definitely interested in the questions about load flex, so we’ll keep following that.

MR. GAGE: The same questioner had a couple of other comments attached to their questions.

I will remind participants that we are only handling questions during this time. You may want to join in with public comments at the end of this presentation, the general public comments, or the written public comments, which Heather has described before.

Continuing on.

“On slide 11, can you explain the difference between 2024 and 2025’s mid case charts for each utility, specifically why some of them dropped out?”

MR. COOPER: I believe the dropout was San Jose. As I mentioned earlier, they had been exploring becoming their own load serving entity, and so we had broken them out separately in the past. And because those plans are on hold, now we’re not breaking them out separately.

I believe, was that the only dropout? Let me take a quick look at my -- yeah, I think that was the only dropout. We also have Palo Alto on there, which is a small load, but it’s in both sides.

MR. GAGE: Thank you. “How did you come up with the confidence levels? Did you do any analysis of utilities’ historical data?”

MR. COOPER: Originally, some of those numbers were shared with us by SCE. I think I had a shot of that in one of the slides, although I didn’t explain it. They had assigned sort of by individual project confidence levels. And I’m not -- and I believe some of that was probably based on experience, but I know they don’t have a ton of data centers in their territory.

We’ve also discussed these confidence levels with various utilities. And, yeah, it think, so it’s sort of based on those discussions, I guess, of, you know, experience, PG&E’s experience, SVP’s experience, you know, sort of floating those numbers. We’ve presented this multiple times and discussed these last year and this year. And so this year, we opted to keep similar numbers to last year, unless there was a specific reason for changing it, such as our revised group definitions.

MR. GAGE: Thank you. “Are all these load profiles applied against IOU time of use rates, or is it all driven by cooling demand?”

MR. COOPER: I don’t think TOU was considered in the calculation. Well, it would inherently. It’s based on AMI data, so inherently, if TOUs are affecting, it would be in the data, although our understanding is that data centers are not really sensitive to TOU rates. So cooling demand would be it, yeah.

MR. GAGE: Okay.

“Can you advise on how the IEPR mid case should be used for resource planning? Is it safe to say that the mid case is sufficiently discounted to address speculative loads, or should LSEs and agencies further discount the mid case forecast to address risk and plan for a lower load forecast?”

MR. COOPER: I would say it is sufficiently discounted, and we have done our best to do the best forecasts, the most realistic forecasts we can.

Oh, Heidi, did you have a thought on that?

MS. JAVANBAKHT: Yeah. Hi, everyone. Heidi Javanbakht with the Energy Commission.

Actually, Mathew, where you’re going with it was perfect. So as far as the data centers, for the mid case, we are primarily counting the ones that have the most certainty around them, which are the least -- and are the least speculative. So I would say that there’s pretty low risk with using the mid case for resource planning.

MR. GAGE: Thank you.

MS. JAVANBAKHT: Of course.

MR. GAGE: Oh, I'm sorry.

"Are you planning to compare distribution-connected data centers against transmission-connected data centers in terms of performance that might skew the data analysis?"

MR. COOPER: Yeah, that is -- we're interested in those kinds of differences. We are sort of digging into our metering data to try to make some of those -- identify some of those differences. As I mentioned, the majority are transmission-connected, so -- and I believe the biggest ones that probably have the most impact are transmission-connected, so we would focus on those.

MR. GAGE: Yeah.

"I believe ERCOT, the Electric Reliability Council of Texas, has adopted a 50 percent discount factor for data center load. Are you looking into how other areas are discounting data center load?"

MR. COOPER: We're definitely interested in hearing any numbers like that, yeah. I assume they're meaning like what we call the utilization factor, which would be the requested capacity in the application, what does that translate to? Like what's the actual maximum demand?

And as I said, the 67 percent was the maximum that Silicon Valley Power said they had seen, so 50 percent, you know, I would think it's reasonable. I believe PG&E reported seeing an average of 60 percent. So, you know, comparing those numbers, you know, I don't know what the exact right one is to use, so we erred on slightly conservative side, but I think definitely would be interested in hearing whatever numbers are out there, yeah.

MR. GAGE: Thank you. That is all the Q&A we have, so I will turn it over to Heather for the public comments and the closeout.

MS. RAITT: Great. Thank you, Jason -- Jesse, sorry.

And then Commissioner -- or Vice Chair Gunda, did you want to make any remarks before I --

VICE CHAIR GUNDA: Yeah, Heather --

MS. RAITT: -- go to public comment?

VICE CHAIR GUNDA: -- I just want to say thanks. Yeah, I just wanted to add my thanks to everybody who attended. I know Commissioner Houck and Reynolds and Commissioner McAllister were there for most of the day. Apologies, I couldn't join the entire day, but really good work in continuing to bring in the known and unknown -- known and pending loads, which has been a very important improvement in the forecasting this year.

I think specific to the data centers, I just wanted to share with the attendees that there is also some work that is happening at the WECC level and in other regional entities like YRAB (phonetic) and CREB-C (phonetic) to really understand how to best forecast data centers given a number of these applications might be happening in different states at the same time and to really understand potential duplication of those applications or kind of just the realization rate. So that's something we're continuing to look for from our regional partners as well.

So with that, I'll pass it back to you, Heather. Thank you.

MS. RAITT: Great. Thank you.

So we'll move on to the public comment portion of the day. And so if you are on Zoom and you wanted to make comments, you can just press that raise-hand icon on your screen. That will let us know that you'd like to make comments. And if you're on the phone, press star nine, and that will let us know that you'd like to make comments. And so comments are limited to three minutes per person, and we requested we only have one speaker per organization.

And so I see we have a hand up and we will go to that person. And if you could --

MR. HART: And if you're able to hear me.

MS. RAITT: Yeah. I'm sorry, and I should have mentioned, could you state your name and spell your name and your affiliation if you have any for the record? Thank you.

MR. HART: Yes. Jon Hart, J-O-N H-A-R-T. I'm the policy director with the California Solar and Storage Association, or CALSSA. Really appreciate all the work going into these reports. Obviously a ton of thought and really appreciate that.

A few comments I wanted to make related to forecasting for behind-the-meter solar and storage. It looks like next year things kind of fall off a cliff as far as, you know, 80 percent decrease in storage adoption and a lot of that due to the ITC. We do expect a decrease in installations compared to now because of the ITC going away.

However, I had made this comment earlier in the Q&A, but the ITC will still be available even for residential over the next two years if it's third-party owned systems. So the ITC is not just going away completely. For non-residential, it will still be there as well, and same thing for storage.

And then also, just based on data and intel we're getting from our member companies, there's still demand out there even without the ITC. So we think an 80 percent decrease is too much. We would be happy to provide data and intel that we've been gathering to help correct that, but we think that that needs to be corrected.

And then also, I think just opening this up in general, we do very often collect data from our member companies. We're happy to provide that and be a resource in moving forward in the future for these or other types of reports.

Thanks again.

MS. RAITT: Okay. Appreciate your comments. Thank you.

Next is Sam Maslin. If you could go ahead and unmute on your end. Go ahead.

MR. MASLIN: Can you hear me?

MS. RAITT: Yes, thanks.

MR. MASLIN: Yeah, thank you. This is great. So my name is Sam Maslin. I'm the CEO of Eddy Energy. Eddy Energy is a developer of community-scale energy storage projects.

Our comment, and we're going to submit comments in writing, is just that at a high level around the load modification process. We would really urge the CEC to really widen the aperture of resources and assets that are included as load modifying resources. You know, the CEC itself has issued relatively recent reports on meeting the load flexibility goal, which I believe is 7 gigawatts. We're essentially halfway there and seem a bit stalled at 3.5 gigawatts. The report from the CEC from June mentions that new strategies and programs are needed in the near term to enable resources and enable the load flexibility that we all know delivers a lot of benefits.

We would really urge that included in that, which is already listed in various, you know, CEC kind of definitions, front-of-the-meter distribution-connected DERs be included as potential load modifiers. I'll talk a little bit about that segment.

This is a segment that's really, frankly, taking off in so many different markets. A lot of people might be familiar with the New York Meter Program and the kind of gigawatts of community-scale solar and storage that's been enabled. But in addition to New York, in addition to ISO New England, we now have states such as Minnesota with the distributed capacity procurement where they're -- you know, they've sort of rated the value and are committing to, you know, 400-plus megawatts of, you know, 3-megawatt front-of-the-meter batteries across their distribution system. We have IRP-driven 150-plus megawatt procurements with Puget Sound Energy, Portland General, you know, and kind of the list goes on.

So there really is a lot of benefit for a wellcited front-of-the-meter community-scale resource. It's in a load pocket. It is actually shifting net load in a really economical and good way. And so we really would urge the CEC to expand its definition to make sure those get counted.

And again, we're going to detail this in our comments. We really want to stress that in California, there are current barriers for those resources to be counted and really come to fruition. So these resources in general don't currently qualify for RA. They're actually barred from seeking deliverability under interconnection rules. These same interconnection rules, you know, study the resources and confirm that they do not back feed to transmission using the local load profile. If they do, they have to go to the cluster and they fail the screen.

So, again, we're going to detail this. But resources that pass WDAT and Rule 21 interconnection processes that are distribution are confirmed to shift local load, to serve local load. We think they ought to be included in the modification process.

Yeah. Thank you.

MS. RAITT: Great. Thank you.

Looking to see if anybody else wants to make comments. Use that raise-hand function to let us know you have comments. And if you're on the phone, press star nine, and that will let us know. And we will just give it another moment to see if anyone else has comments. I'm not seeing any, so I think we're done with public comment.

And I'll just remind folks that written comments are due on November 26. And just look for the notice and I'll tell you how to do that. And then we have our next workshop on December 11th that will talk about the forecast results in the afternoon.

And, okay, it looks like perhaps we can just take one last comment. Karolina, if you want to go ahead and we'll just -- this will be our very last comment. If we can unmute Karolina?

MS. MASLANKA: Hi. Can you hear me?

MS. RAITT: Yeah.

MS. MASLANKA: Hi, this is Karolina Maslanka. Apologies for the last minute comment there.

I just wanted to respond to what Sam Maslin was saying, and also just urge the CEC to consider the expanding what is considered for load modification. And just wanted to ask if you or someone else could speak to the extent to which, you know, that could be considered within the scope of this work and how it would fit into the work that you all are doing on the Demand Forecast, if you could speak to that at all?

MS. RAITT: Yeah, sorry, I can't. We can't speak to that right now, but perhaps staff can follow up with you on that.

MS. MASLANKA: That would be excellent. Thank you.

MS. RAITT: Okay. Thank you.

MS. MASLANKA: And I'll also be submitting comments. Thank you.

MS. RAITT: Thanks.

All right, so that officially closes our public comment period.

And here's the information of how to submit written comments. And I don't know if the Vice Chair wanted to say anything else.

VICE CHAIR GUNDA: Just, Heather, thank you. Thanks to all the participants. And Karolina had the last word, which is great.

So with that, the meeting is adjourned.

(The workshop adjourned at 2:56 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 6th day of January, 2026.

Elise Hicks

ELISE HICKS, IAPRT CERT**2176

CERTIFICATE OF TRANSCRIBER

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

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

I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

January 6, 2026