DOCKETED

Docket Number:	25-IEPR-03
Project Title:	Electricity and Gas Demand Forecast
TN #:	266966
Document Title:	Transcript - 08262025 - IEPR COMMISSIONER WORKSHOP ON ENERGY DEMAND FORECAST LOAD MODIFIER SCENARIO UPDATES
Description:	TUESDAY, AUGUST 26, 2025 9:30 A.M.
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	10/31/2025 1:39:01 PM
Docketed Date:	10/31/2025

STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

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

IEPR COMMISSIONER WORKSHOP ON

ENERGY DEMAND FORECAST LOAD MODIFIER SCENARIO UPDATES

REMOTE VIA ZOOM

TUESDAY, AUGUST 26, 2025

9:30 A.M.

Reported by:

Martha Nelson

APPEARANCES

COMMISSIONERS

Siva Gunda, Vice Chair, CEC

Andrew McAllister, Commissioner, CEC

CPUC

John Reynolds, Commissioner

CEC STAFF

Stephanie Bailey

Quentin Gee, Manager, Energy Assessments Division, Advanced Electrification Analysis Branch

Lynn Marshall, Energy Assessments Division

Andre Freeman, Transportation Energy Forecasting Unit Supervisor

Ingrid Neumann, Advanced Electrification Analysis Branch, Efficiency Analysis Unit

Ethan Cooper, Advanced Electrification Analysis Branch

Bobby Wilson, Distributed Generation Specialist

Mark Palmere, Distributed Generation Adoption Lead

Laith Younis

PUBLIC COMMENT

Kevin Barker, SoCalGas

Jonathan Hart, California Solar and Storage Association

Ben Peters, US Solar

INDEX

INDEX

P R O C E D I N G S

1:00 p.m.

TUESDAY, AUGUST 26, 2025

MS. BAILEY: Okay, well, good afternoon, everyone. Thank you for joining today's Integrated Energy Policy Report, or IEPR, Commissioner Workshop on Energy Demand Forecast Load Modifier Scenario Updates.

I'm Stephanie Bailey with the IEPR Team here at the CEC. This workshop is being held as part of the CEC's proceeding on the 2025 IEPR, and today we're doing a remote workshop using Zoom. This workshop is being recorded, and the recording will be linked to on the CEC's website shortly after the workshop. To follow along today, the schedule and slide decks have been docketed and posted on our website.

There will be opportunities to ask presenters questions. We'll have a few minutes after the speakers to take audience questions, but we may not have time to answer all the questions that are submitted. The Q&A feature is available for you to submit questions. You can also upvote a question by clicking on the thumbs-up icon, and questions that receive the most upvotes are moved to the top of the queue.

Attendees can also make comments at the public comment section at the end of the day. Please note that we won’t be able to respond to comments today, and comments are limited to a maximum of three minutes per speaker, with one person allowed to comment per organization.

Written comments are also welcome, and instructions on how to provide those can be found in our workshop notice, and those are due by 5:00 p.m. on September 9th.

And with that, I will hand it over to Vice Chair Gunda for any opening remarks from the dais.

VICE CHAIR GUNDA: Thank you, Stephanie.

Good afternoon, everyone. Thank you so much for taking the time to join us today.

I want to first welcome Commissioner Reynolds from PUC for joining us today on the dais, and, you know, start with gratitude to the IEPR Team who work tirelessly in putting these workshops, and the Energy Assessments Division staff who are responsible at the CEC for conducting the forecast and much of the analysis.

Also, I want to thank our partner agencies, both CPUC, CAISO, but also the utilities and many of you who work with us very closely, and collaborate to make the products as rigorous as possible. So I just want to start with that thank you.

For specifically the load modifiers, they are used to adjust the baseline forecast and explore various possible futures by adjusting the amount of EV adoption, or building efficiency, energy efficiency, or building electification, and so on. So these are important parts of our work to think about how the potential retail sales at CAISO or other balancing areas of the state will vary based on their penetrations.

One of the core issues that we are tackling with this year is just the uncertainty with the developments of the federal government, you know, combined with the uncertainty that already existed, whether it’s climate change, whether, you know, the system planning issues. We were already starting with a lot of uncertainties, and then the uncertainty of the federal policies just add to that.

So it’s really important from the staff perspective this year, and I’m really grateful for the Energy Commission staff, to look at a wide variety of scenarios so we can have them developed. And as we get closer to the adoption of the forecast, we can really settle on a certain load modifier based on the conditions we see at that moment, so we can have a lot of opportunities to think about the variants in the future.

So looking forward to the conversation, looking forward to the comments, and continuing to make these products as rigorous as possible, as accessible as possible, but also really creating a backbone for planning.

So with that, I'll pass it to Commissioner Reynolds, and then I'll jump into the agenda.

Commissioner Reynolds?

COMMISSIONER REYNOLDS: Thank you, Vice Chair Gunda. I want to express my thanks to you and the CEC for hosting this forum, and echo your thanks to all of the staff who have been performing the analysis to make this possible.

As our agencies continue in partnership with CAISO and the utilities, as you mentioned, to plan for the energy system of the future, how we evaluate future demand is a very critical part of how we can successfully deliver a reliable, cleaner, and an affordable grid. And so I am thankful to the continued partnership between our agencies and appreciate the complexity of evaluating the different potential outcomes for load growth, given all of the uncertainty that you discussed.

I'm really looking forward to today's workshop. I will have to drop off later this afternoon, but I am very much appreciative of the continued partnership between our agencies.

VICE CHAIR GUNDA: Thank you, Commissioner Reynolds.

Again, for the record, for those who are observing, we are one-one today between CEC Commissioners and PUC Commissioners. Thank you.

So with that, I look forward to the rest of the work today, and I'll pass it to Quentin for an overview on the major updates.

Quentin?

MR. GEE: Well, thank you, Vice Chair and Commissioner Reynolds. My name is Quentin Gee. I'm the Manager of Advanced Electrification Analysis at the California Energy Commission in the Energy Assessments Division. Our work focuses quite a bit on the load modifiers. We're also going to discuss a little bit on the rates, electricity rates forecast as well today. But the load modifiers being, at least in this discussion, the load modifiers emphasized today being transportation electrification, building electrification and efficiency, and distributed generation.

As Vice Chair Gunda mentioned, the IEPR is part of this sort of annual, you know, some years, updates, other years, a full IEPR, Integrated Energy Policy Report, forecast that is mandated for us to develop and assist with planning efforts across the state.

We are always striving to improve the IEPR and the forecast. It is something that is -- you know, we're undergoing a very significant amount of change in the electricity system and the planning efforts underway have to match that. And just the amount of change, especially with the uncertainties that we're seeing unfold this year, and also, as Vice Chair Gunda mentioned, the uncertainties that already sort of exist in this space, you know, there's just a whole lot for us to keep track of. And our team of about 40 different staff across the Energy Commission, in the Assessments Division, forecast, work on this forecast to really try to get a hold on how best to really think about the electrification that we're going to be seeing in the next decade plus.

Yeah, so some of the uncertainties, just to highlight, I know that the staff presenting will talk more about this, but I'm sure many folks attending have heard about the different areas of uncertainty that have emerged. We're looking at the ending of electric vehicle or zero-emission vehicle incentives at the light-duty and the medium- and heavy-duty level. We're looking at incentives for homeowners and families to be able to purchase efficiency upgrades and, you know, heat pumps and other incentives for distributed generation.

So all across the board, we're seeing a lot of different uncertainties. But at the same time, we also know there are some technological and market fundamentals that are driving this. And that's what we'll be exploring in further detail today.

So with that, I will hand over to Lynn Marshall, who will discuss the rate forecast. And then we'll talk further on some of the load modifiers.

Lynn?

MS. MARSHALL: Hey, good afternoon.

You can go to the next slide.

So I'll be presenting the Retail Electricity Rate Forecast that's an input into our various demand forecasting tools. So this forecast starts with forecasting revenue requirements by looking at procurement costs, LSE's current procurement plans, expected energy prices, projected transmission and distribution costs, programmatic activity, other policy impacts. Then we take that forecast of total revenue requirements and divide it by the sales forecast. And that gives us an annual average rate. So this is an all-in rate. It doesn't address rate design issues like fixed versus variable charges. And that is the input that goes into our sector models, self-gen, transportation demand, and fuel price forecasts.

Next slide.

So what's new for this year?

Okay, so first, as always, we have to start with the sales forecast from the previous cycle because this is a model input, so we don't know what the result of this year's forecast will be. So we're using the planning scenario from the 2024 IEPR.

Next, because this is a full IEPR year, we have the larger utilities and other load serving entities submitting demand forms as well as their supply forms. And those include information on their projected revenue requirements, including procurement, transmission, distribution, other programs that they have planned.

So that gives us a picture of kind of the cost of the resources they have planned to where there's a net short between the resources needed to meet the demand forecast and what the LSEs are planning. We use energy price forecasts to value that net short, so using the wholesale energy prices that were developed for the 2024 avoided cost calculator, along with the forecast of capacity prices.

For transmission revenue requirements, we're using either what was submitted by the utility, and that tends to be mostly near term, or then escalating that up four and a half percent annually. That's the same assumption as last year.

Now, for the general rate case, we have -- you know, all of the three IOUs we'll have either a pending or recently adopted, now a four-year plan. Beyond that, in the last forecast, I assumed those costs were escalated at five percent annually. Because of the buildup in rate base we're seeing associated with all of this large capital expenditure for wildfire risk mitigation, I'm using six percent through 2030, and then going back down to five percent.

And then next, and this is not new, I'm using the Public Advocates Office DGEM model as a benchmark to account for the incremental distribution system upgrades that are going to be needed to support grid electrification.

Okay, so can go to the next slide?

And the other major change was to add an accounting for the grid investments that'll be needed to support data centers; right? So we don't have a lot of data on what these will cost. We have a statement by PG&E in an investor briefing that the capital cost associated with the grid infrastructure, substations, et cetera, range from $500 million to $1.6 billion per gigawatt hour.

So for this forecast, I'm using the high end of that range. I'm using 1.5 billion per gigawatt. That's a capital expenditure. And then we translate that into an annual revenue requirement. I'm using some multipliers that are provided by PG&E in their GRC work papers, converting CapEx to a revenue requirement. So that's what's shown on this graph here.

So I'm using the gigawatts additions annually from our last forecast. And that ramps up pretty quickly through, you know, now through 2035. And then the red line is the annual cumulative revenue requirement, so increases steeply, then it does decay as those additions to rate base are depreciated. So that will be included in the rest of the results.

So next slide.

So now taking a look at the total, -- oh, wait, forgot...

So what are the impacts of that data center revenue requirements at a high level? This is just the system average rate. And even with the high cost assumption that I'm using here, it does lower, still lower the system average rates. It's like one and a quarter cents per kilowatt hour. So obviously if this is an overestimate of the CapEx that's needed, then the benefit in reducing rates will be larger.

So this, the whole question though, of the interconnection rules and rate design, is currently being addressed in the PUC Rule 30 proceeding. So we can estimate the average rate on the system. Ultimately, the impact on your residential versus industrial customers is going to depend a lot on rate design and the other rules developed in that proceeding.

Okay, so next slide.

So this is showing the total revenue requirement needed for the whole PG&E service area. And that includes procurement costs for LSEs other than PG&E.

So the first thing you may notice is this. So we have this big run up in total revenue requirements peaking in 2024, and then it's declining and leveling off. So if you'll notice those orange bars, that is a cost associated with wildfire mitigation, catastrophic event cost recovery. So that has pushed up rates. Recently, however, those costs are being now being paid off, and so they can be removed from rates. And then going forward, more of those wildfire mitigation costs can be securitized through the AB 1054 process so there's more of a levelized payment and a savings to rate payers by paying a lower interest rate.

This includes the PG&E's current pending general rate case. It starts in 2027, and it does include their full request there that was only recently filed. And sometimes we'll make, depending on the intervenor positions, make a reduction, but I don't yet have testimony by intervenors in that proceeding. So this includes about almost 12 percent increase in 2027, followed by almost 8 percent attrition increases in the following year.

The other thing I want to point out about this is the transmission revenue requirement, the red band. And we did use PG&E's submitted forecast through about 2035. And there are some pretty significant increases in there, about something like eight percent annually and then over the next 8 to 10 years. And then on the very top, that pink bar, we're also stacking the incremental grid electrification costs. So overall, there's higher revenue requirements than the previous forecast, in particular, in the near term.

So next slide.

This shows the SCE area revenue requirements. You've seen in the last few years, their base GRC increased a lot to account for wildfire mitigation spending. It did include the proposed decision in that case, which approves, I think, something like 13 percent test year increase. However, there's a delay in -- because there's a delay in approving that, the under-collection is going to be amortized over a two-year period. So that kind of softens the impacts that customers will see over the next couple of years.

Another addition I made for the wildfire mitigation costs was to add in about $800 million to account for future wildfire expenses. It does take a couple of years for those to show up at rates. So looking at some of the past wildfire events, that was just an estimate of what seems plausible.

So next slide is the San Diego area. They had a sort of caveat. Their GRC distribution did increase 17 percent. The actual approved -- test year approval was only seven or eight percent. But there was some other costs to be amortized and other adjustments that we've made, so that ended up being a larger increase. And I think the current transmission outlook is somewhat lower than we were previously forecasting.

So next slide.

Okay, so what does that look like on rates? So in the near term, they're somewhat higher. And even though we've increased some of the assumptions around revenue requirements, they're still relatively flat, actually slightly declining in the near term. But then as we have more demand growth and the revenue requirement growth, we actually see some noticeable declines in the 2030 to 2040 period. And then real rates are starting to increase again.

And the next slide is the SCE area. And this is not -- on that, not very much changed. The recent PD and the GRC case was actually pretty similar to the assumptions we used last time. So with the exception of increasing some wildfire costs, overall, there -- the overall forecast is not much changed.

And then the next slide is San Diego area. And we did have an overestimate of estimate of transmission and some other costs in the previous forecast. So this is more aligned with the current rates and I think the current outlook.

So next slide.

Now, so far, I've only talked about the IOUs and we do forecast for all the planning areas in the state. So taking a look just for the residential sector, the publicly owned utilities are looking at some significant rate increases. Burbank and Glendale are. I think, Burbank looking at something like eight, nine percent increase over the next couple of years, Glendale less so, but they have repowering costs and higher procurement costs to meet RPS goals and some transmission system upgrades.

LADWP, this is the forecast that their staff submitted. It is their LA100 Case 1 Scenario. And so this reflects quite ambitious goals in their LA100 Plan, which include everything from some in-basin hydrogen, energy efficiency, DERs. It's a very broad based plan.

They are still currently in kind of a public outreach process meeting with their advisory group. So they have not -- the Board has not adopted this plan and they do actually have another scenario, SB-100, that's, I think, about 20 percent lower. So that's -- well, we'll have to see what they -- the decision they finally make.

The BANC, that balancing area of Northern

California, that is SMUD largely, and they have continued to keep rate increases close to the rate of inflation. That’s their goal. So they’ve been effective at that so far.

So we take all of those, all of the planning area rates -- go to the next slide -- and construct a weighted average to produce our statewide average rates. And this is used for transportation demand models. And it is higher in the near term. And then it kind of, like we saw with residential, with PG&E lowering, declining a bit, and then as demand growth slows, rates start to increase.

So that’s -- okay, next. Let’s go to the next slide.

So conclusion, there will be a workbook docketed in the 25-IEPR-03 that will include the rate forecast, the revenue requirements, and discussion of the key assumptions and data sources. So you can look for that if you want more detail.

There’s quite a few uncertainties here. This forecast is implicitly assuming that we don’t have the large-scale, you know, catastrophic events or growth in climate change adaptation costs. That could change for data centers looking forward to getting better data out of Rule 30 proceeding, or as we work with the utilities and the IEPR process. And then we don’t have an explicit accounting for the plans that might be needed to meet SB 100 with respect to transmission over the long-term.

And with that, I will open it up to any questions.

VICE CHAIR GUNDA: Yeah, thank you, Lynn. I'm going to hand it off to Commissioner Reynolds. Just have one question.

Just on the jurisdictional revenue requirements that you covered --

MS. MARSHALL: Yeah.

VICE CHAIR GUNDA: -- I just want to understand, are each of those years' revenue requirements, divided by the sales will get new --

MS. MARSHALL: Mmm hmmm…

VICE CHAIR GUNDA: Okay. So I kind of wanted to understand on the PG&E and others, so is it -- you know, for me, I mean, just taking it from here, that the wildfire costs continue to decline as a part of the revenue requirement?

MS. MARSHALL: Yeah. And I should point out, though, there's still some of that activity, but it will be going forward. It's folded into the general rate case. So it's not always broken out. What is always broken out is things like the specific event cost recovery, or before they had a GRC application pending, they were kind of speeding this process up so they could go ahead and file a separate application. So not all of that activity is in a separate application. And then we still have things like the wildfire funds charge that rate payers pay. And then there's the long-term securitized bonds that have to be paid.

VICE CHAIR GUNDA: Got it. Thank you. And thank you for discussing just the rate increases that we expect in the POU territory as well. I think that I'm kind of like watching that IRPs from the POUs is really helpful, Lynn.

I'll pass it to Commissioner Reynolds, and we can go to Q&A from there. Thank you.

MS. MARSHALL: Okay.

COMMISSIONER REYNOLDS: Thank you, Vice Chair, and thank you, Lynn. I'll ask a brief follow-up, just acknowledge that it's really helpful to see some forecasted revenue rate adjustments laid out in these charts.

And just as a specific example, going back to the last PG&E GRC, given that there was a substantial portion of wildfire-related funding in that GRC, that's actually going to show up in the chart in the distribution section; is that right? So the --

MS. MARSHALL: Yeah.

COMMISSIONER REYNOLDS: -- wildfire hardening, the veg management, all of that’s going to fold into distribution, so there’s sort of a GRC wildfire that’s embedded in that --

MS. MARSHALL: Yeah.

COMMISSIONER REYNOLDS: -- larger distribution column, and then there’s kind of a separate wildfire applications?

MS. MARSHALL: Yeah, exactly.

COMMISSIONER REYNOLDS: Oh. That’s helpful to understand. And I, you know, I appreciate that it’s, especially with GRCs having so many topics, it’s really hard to dis-aggregate kind of what spending is for what topic. But it’s also, I think, helpful for everyone to understand that there are real wildfire costs embedded in the distribution bars there.

MS. MARSHALL: Mm-hmm.

COMMISSIONER REYNOLDS: Thank you.

VICE CHAIR GUNDA: Yeah, thank you, Commissioner Reynolds. I think I was going to ask why the transmission contribution is so much smaller than the distributions. That makes sense. Thank you so much.

So just to kind of making sure, so the GRC distribution, like just the ballpark, what share of that would be wildfire, like maybe 50 percent, 20 percent?

MS. MARSHALL: I’m thinking PG&E’s current application is 30 percent, maybe. Does that sound right? You know, going back was maybe larger. I mean, they just, they have done over the last few years just a huge amount of spending in a short time. And so I think we'll get it more levelized to where it's a steady state. So if I'm remembering right, 30 percent is the current share.

COMMISSIONER REYNOLDS: Definitely seeing some significant portions, at least in the revenue, since they're associated with wildfire risk reduction efforts (indiscernible) by utilities.

VICE CHAIR GUNDA: Thank you, Commissioner Reynolds. I don't know, Commissioner, if you have any other questions or we can move to Q&A?

COMMISSIONER REYNOLDS: That will do it for me. Thank you.

MR. YOUNIS: Lynn, I have one question from Tom Cabot regarding slide five. I don't know if you want to pull that back up, but I'll go ahead and read it.

> "Does it make more sense to show the data center impact on the customer class that contains data centers, commercial and industrial class in question, or are there proposals to co-mingle costs and revenues across customer classes?"

MS. MARSHALL: Okay, well, good question. That will all be fodder for a rate design proceeding coming to the PUC hopefully in the near future.

But generally these are transmission costs and generally transmission costs are allocated to all customers. So they're not going to be -- you know, they're adding substations, et cetera. They're not going to allocate it to a particular customer. So it's generally based on marginal cost of service. So the transmission costs tend to be spread out more evenly across customer classes. But, again, this will be something for the PUC to take up.

MR. YOUNIS: Great. I have another one in from Roger Lin.

"Is the use of the high end 1.6 billion revenue requirement for PG&E data centers consistent with most conservative scenarios for data center planned for the IEPR?"

MS. MARSHALL: You know, I don't know that we are using that cost assumption anywhere else. And I haven't -- I couldn't find any other sources or actual data on data center build because this is a very specific question of how much is it going to cost the utility to upgrade the grid to support these new resources?

So I'm hopeful that, in say, the Rule 30 proceeding, we'll get more actual data, or as they get into rate design proceedings, we'll start to see that data, but -- and it is a high estimate. Probably overestimating, but since this was the first time we were doing this, I kind of erred on the side of being more conservative.

MR. YOUNIS: All right. And I have one last question from Dante Ramirez. "Why does California have higher or highest electricity prices in the country?"

MS. MARSHALL: Well, that's a broad question, probably beyond the scope of this IEPR. And you do want to look at specific utilities. Not all public utilities have that high rates, but wildfire mitigation cost has been a big driver.

I think I would refer you to the PUC SB 695 reports, which discuss also some other causes, rather than trying to rehash all of that here. And if you want follow up, I could provide a good contact and provide you a link.

MR. YOUNIS: Sorry, one last question just came in from Kevin Barker. "Does the transmission costs include additional transmission cost assumptions from CAISO's TPP?"

MS. MARSHALL: No, not explicitly. And that is, I called out on the last slide of bullets, is we really haven't tried to sort out what the incremental cost over the assumptions -- over what's in the IOU's forecast or our baseline assumptions of what that would cost. So that's definitely something we want to work on in the future.

MR. YOUNIS: That's all I have. Thank you, Lynn.

Back to you, Quentin.

MS. MARSHALL: Okay.

MR. GEE: Great. Thank you, Lynn.

Oh, okay. We have one more question. I think we have a little bit of time for that, but we need to move on after this question. So we've got a question.

Well, no, I think so, Cameron, definitely appreciate your question. I think that is good for the public comment period. We're focused on the sort of the technical aspects of how the rate forecast works. So I think this is getting a little bit out of scope from what we traditionally look at in these proceedings. I think Lynn has pointed some areas that are good areas for investigation of those kinds of questions.

But thank you very much, Lynn. We appreciate your expertise on this. And what we'll do now is we will move on to our next speaker.

Before we do that, I did want to make a quick note to people. I forgot to mention this before, but we have heard that some people are interested in some of the more technical details of our work. And I just wanted to kind of flag for those folks that are interested that we do have, outside of the IEPR workshops, which is what we're attending now, we do have a Demand Analysis Working Group. This is where we get into deeper questions, more technical issues on how the sort of the nuts and bolts of the forecast work. So I'm going to go ahead and post in the chat a link to the Demand Analysis Working Group. It's publicly available. Folks are free to, you know, attend the working group meetings virtually or in person. So we will be able to provide that link to you here in a second.

But now we will move on to the transportation electrification forecast with Andre Freeman and he'll kick it off.

Andre?

MR. FREEMAN: Thank you, Quentin. Just wait a minute for the slides to come up here. Great.

So good afternoon, everyone. My name is Andre Freeman. I'm the Supervisor of the Transportation Energy Forecasting Unit here at the Energy Commission. Today, I'll be providing a high level overview of our transportation modeling processes, as well as discussing some of the high level concepts and considerations that we're looking at for this year's forecast.

Next slide.

So I'll try my best to limit usage of acronyms during this discussion. But here they are, if anyone needs to reference back to them. I do want to highlight the first definition here, which is AATE, especially for folks who haven't heard this terminology as before. This stands for Additional Achievable Transportation Electrification. We define this as a managed forecast scenario type that seeks to kind of effectively reflect the impact of policies across various scenarios that would be otherwise difficult to reflect in just a, you know, straightforward demand side vehicle choice modeling.

And as part of this, we try to bake in reasonably anticipated market changes. We'll see changes that we have details on, and then just general programmatic conditions that might impact transportation sector in the coming years. But I'll talk a little bit more about this in later slides.

Next slide, please.

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

One of the key purposes that this forecast serves is to inform a balanced approach to 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 on the flip side, underestimating the rate of growth could also lead to delayed development of the much needed infrastructure to support electrified vehicles and prevent California from achieving its climate and public health goals.

So 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 fuels that those vehicles use, how much they will travel, and other factors that will impact how much fuel they're consuming throughout the year. As you'll see in the next couple of slides, we use a complex series of models and other data sets to help inform how transportation choices will change over time.

Next slide.

So taking down a level of detail. I don't expect you to, you know, see everything on this flowchart. I'm not going to go through every item. But I did want to kind of highlight that we do have, you know, an interconnected web of data and models that we use. This one was used for past forecasts, so just an illustrated example here.

As you can imagine, tracking the rapidly evolving world of transportation technologies, assessing changes in consumer behavior, forecasting the ebbs and flows of transportation fuel prices, and applying economic and demographic indicators to our projections requires a lot of gathering -- a lot of data gathering and analysis, and updating these models over time so that we're, you know evolving as the transportation sector evolves.

We'll be keeping a close eye on some of the federal data sources that we rely on. We're hoping that those, you know, stay as reliable as in the past and they are on a timely basis. But we do kind of take a snapshot in the middle of the year of what's going on in the transportation sector and projections for things like future fuel prices and adoption rates, and then we'll apply that to our transportation forecast moving forward.

So using some of the data sets that we have highlighted here as inputs for our models, we're able to determine vehicle choices and other vehicle adoption patterns and how they might change over time, as well as changes in demands for various modes of transportation. The resulting information allows us to determine the overall changes in future vehicle populations and derive the demand for electricity and other transportation fuels that these vehicles may rely on.

Next slide.

I do want to go through some of the definitions we use for our various forecast types here.

So the baseline is not necessarily just, you know, business as usual, we assume nothing's going to change. It definitely looks at things like historical trends, impacts from existing, you know, approved policies that will be impacting the way the transportation sector grows in the future.

And then as I mentioned before, the Additional Achievable Transportation Electrification scenarios in the IEPR are really used to explore a range of potential future energy demand impacts, particularly those related to transportation sector and, you know, associated load types beyond what we typically include in the baseline forecast.

So these scenarios will help policymakers and other stakeholders really understand the potential consequences of different energy policies and market trends, allowing for more robust planning and decision making processes to happen.

Next slide.

So as I mentioned before, the AATE scenarios are built to reflect a variety of possibilities from implementation of state policies. This will range from recent higher confidence actions to longer term aspirational goals to which we assign different numbers of AATE levels ranging from, again, we have increased amounts of certainty about what's going on, all the way ranging up through some, again, some of those aspirational goals where we may not have all the details of how we might get there quite yet.

Next slide.

Some of the latest policies impacting the transportation sector is the recent executive order that reiterates California’s commitment to further developing the zero-emission vehicle marketplace. The governor’s executive order called for state agencies to do many things, including starting development of the next wave of clean car regulations, identifying new incentive mechanisms that might promote clean transportation options, continue working with truck manufacturers to accelerate the deployment of medium- and heavy-duty zero-emission vehicles, take steps to ensure that the state is doing its part so that the vehicles within our fleet are clean vehicles moving forward, and many other supporting efforts that will help strengthen the continued growth of zero-emission vehicles throughout California.

So how does this translate to our modeling work?

Next slide.

So last year’s transportation forecast focused on two primary scenarios with the standard baseline assessment of zero-emission vehicle growth and an Additional Achievable Transportation Electrification scenario that reflected implementation of both the Advanced Clean Cars II and Advanced Clean Fleets regulations. Based on changes in policies and regulations that happened earlier this year, we realized the needed to update some of these base assumptions in our modeling.

Next slide.

So for the 2025 IEPR, we plan on revamping the series of Additional Achievable Transportation Electrification scenarios to reflect changes in policy and the significant amount of uncertainty prompted by recent actions at the federal government. We'll look at different growth rates across light-, medium- and heavy-duty vehicles with a focus on how California may continue trajectory towards meeting zero-emission vehicle goals. We'll incorporate policy changes associated with the federal actions, including the removal of the federal tax credit for personal and commercial zero-emission vehicle purchases. We'll also do things like update vehicle stock information population to make sure that we're reflecting historical growth in zero-emission vehicles.

But I do want to, you know, highlight the fact that due to the timing of the IEPR and the ongoing uncertainty and limited data availability around changes in vehicle pricing that could come due to tariffs, manufacturing profit changes and other factors, we won't necessarily have a complete picture of the pricing aspect of our modeling inputs.

But, again, like I mentioned before, we kind of take a snapshot in time of where we're at right now, use the best available data and make sure we're utilizing that to model. But we'll likely talk about, you know, later in this year to early next year as the IEPR development process goes through, as things change, we'll be able to at least reflect that in the narrative.

So the multiple scenarios we're proposing in response to this uncertainty caused by these changes, I'll get into in the upcoming slide.

Next slide.

So these are possible pathways based on potential policy and market transitions. The high case scenario here is similar to the adoption schedule that you'd see if you saw the Additional Achievable Transportation Electrification scenario for the 2025 IEPR, but slightly lower based on lower market share and the other changing conditions I previously mentioned for the light-duty vehicle sector.

Then we'll also look at for the moderate case, really basing that on potential market growth and implementation of reasonably expected future policies based on the clearly articulated state priorities, but definitely on a longer timeline. Again, given the levels of uncertainty that we're experiencing and again, some of those recent federal actions that may delay, you know, California implementing, you know, some of its goals or implementing actions to get to some of its zero-emission vehicle goals.

Next slide.

So on the medium- and heavy-duty vehicle side, similarly, we have a high growth trajectory here. You know, our baseline forecast in 2024 is shown here. So our baseline forecast in the 2025 IEPR will likely be, you know, a little bit similar to the 2024 baseline. Like I mentioned before, we'll have updated inputs that will help inform to see if that shape will have changed any compared to last year's numbers. And then we'll have a high growth scenario that, again, really looks towards, you know, additional growth that happens over the long term to really move California towards some of its aspirational goals in this sector.

Next slide, please.

So as more data becomes available, likely over the next 6 to 12 months, we'll be able to provide a more updated forecast for the 2026 IEPR that includes, you know, any specific quantifiable actions that are detailed in response to the governor's executive order that I mentioned earlier.

You know, over that time period, we also expect to see tariffs and other economic impacts start to play out where we’ll have a lot of real-world data to work off of, so we won’t have to speculate, you know, how those things will play out. So we do expect that type of, you know, price and consumer cost and price information to be available, you know, at best, maybe late this year, early next year. So we’ll try our best to incorporate it into next year’s IEPR.

We’ll also be looking at changes in consumer behavior that have not been reported, that were reported through our recent California Vehicle Survey. We’ll match that information up with some of that, you know, economic data that I just mentioned on vehicle pricing. And we’ll utilize that to have a more updated picture of what consumer adoption rates may look like.

We’ll also start looking at updated load shapes based on analysis of real world meter data for EV charging facilities. That should help us continue to be able to accurately reflect what’s going on out in the world, especially as EV charging is, you know, rapidly evolving and consumer behavior in that area is evolving as well.

And we’ll also look to update emerging technologies. You know, we’re always keeping an eye out for the latest and greatest technologies that may influence the transportation sector as a whole. This could include major advancements in, you know, battery or other fuel type technologies. But we're also looking at things like impacts in the future that autonomous vehicles may have on passenger travel and travel behavior just in general. For things like that, we are really looking to have some, you know, sound data to base some decisions off.

I think at this point, especially for things like autonomous vehicles, there's a lot of speculation, but not a lot of hard data for us to really start baking into our modeling. So as that becomes more available, we'll continue updating our models so that we have, again, that updated view of what the future of the transportation sector looks like.

Next slide, please.

Okay, I'll turn over to dais for questions.

COMMISSIONER REYNOLDS: Thank you, Andre, for the presentation. I have a brief comment and I think we can open up Q&A unless the Vice Chair returns.

You know, I really appreciate all the work that's going into this forecast, and I appreciate the uncertainty-related challenges that you and the team need to account for as you're evaluating our future demand scenarios.

I just wanted to acknowledge that, you know, in addition to the way that transportation electrification will impact our resource planning as a state, which will be very impactful and we will need to prepare for the different potential scenarios, particularly when we look at medium-duty and heavy-duty vehicle electrification, there will be potentially significant distribution and transmission system impacts and be really important for us to be very careful about how we how we plan to account for the potential impacts on the system and, ultimately, try to get as close as we can to predicting the future and putting ourselves in a good position to plan infrastructure very efficiently to meet that future.

That’s it from me. And thanks again, Andre. And I think we can turn to Q&A.

I see Vice Chair Gunda.

VICE CHAIR GUNDA: Yeah. No. No. Thank you, Commissioner Reynolds. No questions for me.

I just wanted to say, Andre, great presentation. Thank you. I benefit from a lot of internal conversations and really want to uplift Commissioner Reynolds’s point on different types of transportation electrification impacts, different types of projects on the infrastructure. And so I think, you know, the uncertainty transit translates to different levels of rate impacts. So, you know, I just wanted to emphasize that.

Thank you, Commissioner Reynolds.

With that, I'll pass it over for the Q&A.

Quentin?

MR. GEE: Thanks. No open questions right now, Andre. Thank you so much.

COMMISSIONER REYNOLDS: Yeah, thank you, Andre.

MR. GEE: Yeah, we had one question, but we were able to quickly answer that in the chat with the link. All right. So thank you very much, Andre.

And we are now going to move on. We're a little bit ahead of schedule, which is good. But I'm going to go ahead and move us on to the energy efficiency and fuel substitution updates. For this discussion, we have Ingrid Neumann and Ethan Cooper doing a presentation on AAFS and AAEE, so we call it.

So Ingrid?

MS. NEUMANN: Hello. Can you hear me?

MR. GEE: Loud and clear.

MS. NEUMANN: Perfect. Okay, just wanted to double check.

Hello, stakeholders and Commissioners. I'm Ingrid Neumann, and I would like to discuss AAEE and PiCS AAFS in detail after I introduce how the full AAFS and AAEE load modifiers are constructed.

Next slide. Next slide.

This is a handy list of acronyms, initialisms and abbreviations you can refer to any time.

Next slide.

So additional achievable energy efficiency savings and fuel substitution impacts are designed to capture a range of incremental market potential impacts beyond what is included in the baseline demand forecast, but they are within the range of what is reasonably expected to occur.

You can see on the bottom of this slide a chart which has one row at the bottom for AAEE and two rows for AAFS. So this is to note that AAFS consists of two distinct components. The PiCS, which is programmatic in incremental codes and standards, which I'll discuss in detail later in my presentation, and the zero-emissions portion that my colleague Ethan Cooper will discuss in a subsequent presentation.

Next slide.

Both AAEE and AAFS reduce gas consumption.

Next slide.

While AAEE also reduces electricity consumption, AAFS increases electricity consumption. Thus, AAEE has savings and AAFS has impacts.

Next slide.

We need to consider which combinations of AAEE and AAFS scenarios are compatible with each other, given total gas displacement potential and program funding sources. We can construct scenarios with various goals in mind. For example, it’s possible to combine AAEE and AAFS scenarios differently for electricity planning purposes than for gas planning purposes. We also can have different orders of operations. I’ll speak about which one we choose in a moment.

Next slide.

First, we need to understand that AAEE scenarios can be separated by fuel, i.e. gas and electricity savings can be separated.

Next slide.

AAFS scenarios are, however, not necessarily coupled. They have dual impacts. As gas consumption is removed, a small amount of electricity consumption is added.

Now for our order of operations.

With our focus on decarbonization, we have chosen to prioritize electrification over gas energy efficiency due to the four times greater GHG impacts. So what we do is we start with our gas consumption. We apply the PiCS AAFS first and then the zero-emission AAFS portions according to the scenarios that Ethan will discuss later. Finally, we apply gas AAEE. Electricity consumption comes along for the ride in steps one and two, and then a different or perhaps the same AAEE scenario can be chosen for electricity because those can be separated.

Next slide.

So now I'm going to focus specifically on AAEE and PiCS AAFS.

We live in a shifting building energy efficiency and electrification policy landscape, and some of that will affect the uncertainty in our 2025 forecast. In this chart, we have four rows which show the biggest impacts.

AB 130 affects Title 24 Building Energy Efficiency Standards by prohibiting updates to the residential code in 2028. This means that the 2025 standards will remain in place, but upgrades to or improvements to the residential sector may not be considered in 2028. But they may be considered in 2031. This does not affect the non-residential sectors.

Now, in the second row, we have 17 measures on DOE's list to rescind. So those federal appliance standards might cause stranded EE savings if they are removed. One can argue that the market may not revert back to less efficient appliances. However, new actors selling less efficient appliances could enter the supply chain. Maybe that will be slowed down by tariffs. There is a lot of uncertainty here.

On the other hand, California may continue to enforce measures that are not federally preempted. Currently, it looks like nine of the 17 measures on the list to rescind may be federally preempted, but the others are likely not, and California could continue to enforce them.

In the third row, we're looking at how CARB has delayed their zero-emissions space and water heating standard Board hearing until after 2025. This affects the zero-emissions AAFS portion that Ethan will talk about a lot for existing buildings.

For the PiCS piece, we are taking that into account. So what that means is that currently IOU and POU electrification programs that consider rebates or other incentives after 2030 for water heating and HVAC are eliminated. So we are considering that that will be in place. This doesn't affect other end uses for electrification, and it doesn't affect energy efficiency in those end uses. So, for example, more efficient heat pumps, you know, more efficient electric appliances for water heating and HVAC could still be incentivized.

We are also considering an IOU sensitivity run for no zero-emissions water and space heating simply to compare the magnitudes of impacts and bound our uncertainty for the PiCS, AAEE and AAFS better.

In the last row, we have the One Big Beautiful

Bill Act, which sunsets IRA funding in 2025 rather than in 2034. This will directly impact the effects -- or directly impact the IRA-funded programs and programs that coordinate with that for EBD.

So let’s move on to the next slide.

These are AAEE scenarios as modeled in 2023, which was our last full cycle. The scenarios ranged from conservative to optimistic, starting with one and ending in three. The business-as-usual type of scenario for planning was traditionally picked as Scenario 3. That may be different this time around.

We are showing on the right hand side a sampling of the programs and codes and standards that are included by scenario, and we will retain a similar framework for the 2025 update this year. So same components, similar scenario design but, of course, different savings because of new data and all these policy uncertainties.

Next slide, please.

So here we have some significant considerations for 2025’s AAEE modeling. The first, we simply have a new data source. The CMUA potential study is updated every four years. So the last time we had a new one was in 2021. And now we just received their new energy efficiency projections as part of this potential study in 2025.

Then the other three items are the policy changes that we've already mentioned. AB 130 pausing new residential standards for the 2028 cycle. So that, of course, affects our Title 24 modeling in the residential sector. It shouldn't affect things in the non-res.

And then the 17 measures on the DOE list to rescind will affect our federal appliance standards modeling and what scenarios those end up in.

Lastly, IRA funding being eliminated at the end of this year, rather than in the next decade, will affect the savings expected from the home efficiency rebates, or HOMES IRA incentive.

Next slide.

Here we have a similar slide for the PiCS AAFS that were modeled in 2023. Again, the scenarios range from conservative to optimistic one through six. And we have a sampling of the programs and codes and standards that are included here. We will retain a similar framework here, as well, for the 2025 update to the PiCS AAFS, same components, similar scenario design, differing impacts for those portions that are affected by new data or policy changes.

Next slide.

So here we are also looking at some new data from the CMUA potential study received in 2025 that, to our great excitement, did include electrification projections for the 40 covered POUs. And we're working with the CMUA on how to incorporate that, which is much better data, in our modeling.

Then, of course, we have the policy changes that, from AB 130, that affect any electrification in the residential building sector under Title 24, that since the 2025 standards will remain in place, we do still expect to see electrification in new construction, but there won't be new end uses or new measures added in 2028. We can't anticipate that until 2031. On the other hand, we have received data from the CPUC on energization for the IOUs, which show higher IOU levels of electrification than we initially assumed due to the building standards in 2023.

Lastly, the IRA funding being eliminated this year rather than in 2034, as well as some budget adjustments that occurred after we built the workbooks for Equitable Building Decarbonization in 2023, we'll show some decline in the impacts expected from IRA funded decarbonization and equitable building decarbonization programs.

Last slide, please.

Thank you for your participation. We are definitely interested in your questions, comments and feedback, but I'd like you to hold those, please, until after my colleague Ethan Cooper presents on the zero-emission AAFS impacts in the full proposed AAFS-AAEE scenarios for 2021. Thank you.

And Ethan?

MR. COOPER: Well, I was muted. Can everyone hear me now?

VICE CHAIR GUNDA: Yes.

MR. COOPER: Thank you. Hello, everybody. I’m Ethan Cooper. I’m a Building Decarb Load Allocation Specialist here in the Advanced Electrification Analysis Branch, and today I’m going to be presenting on our draft 2025 IEPR AAFS scenario characterizations. And Ingrid mentioned, I’m going to be specifically looking at the initial zero-emission appliance standard modeling aspects.

Next slide, please.

Here’s just a quick list of acronyms and initialisms I’ll be using throughout today’s presentation. You can use this slide as a quick reference in case you encounter any unfamiliar abbreviations, but I’ll do my best to reduce abbreviation lettering where I can, especially when introducing any new terms.

Next slide, please.

Before going into our scenarios, I do want to note that we see some shifts in the building electrification policy landscape, which have created some uncertainties for our zero-emission appliance modeling that were not present in previous integrated energy policy report or IEPR cycles. I'm going to discuss some of the uncertainties surrounding our programs in the equivalent codes and standards or PiCS modeling for additional achievable energy efficiency and fuel substitution.

I also want to go through some of the uncertainties that are surrounding our additional zero-emission appliance modeling that's done in FSSAT with a fuel substitution scenario analysis tool. FSSAT really just looks at modeling zero-emission rules and standards, and it's a category fuel substitution, which is distinct from all the PiCS components that Ingrid mentioned in her slides previously.

So as I mentioned earlier, there have been some shifts or some changes in the zero-emission policy landscape since our 2023 IEPR cycle.

First, looking at the South Coast Air Quality Management District, as some of you may be aware, on June 6th, their board objected a bill that delayed and already limited version of the proposed amendments to the Rules 1111 and 1121, which were looking at proposing zero NOx appliance sales targets. Comments of the Board hearing for these rules stated both affordability and grid reliability concerns for the proposed amendments that would be made to these two rules.

Additionally, the South Coast adopted Rule 1146.2, which looks at zero-NOx rules for certain water heating appliances that came into litigation in late last year. However, on July 18th, there was some good news to the rule as it was upheld by federal courts, so it's going to be continuing to move forward.

Looking at the Bay Area Air District, they are currently looking at making some potential amendments to their currently adopted Rule 9-6, to help with addressing some installation costs and equity challenges that are being seen with a subset of the water heating appliances that are being targeted by this rule.

Looking at the California Air Resources Board Regulations, Congress is now planning to delay their Board hearing on the zero-emission space and water heater standard until after 2025, which was the year it was originally planning to go board for adoption.

When looking at the federal standards side, the U.S. Department of Energy, or DOE, finalized their energy efficiency standards for residential electric water heaters back in April of last year, and that's going to be going into effect starting in 2029. The standard here just kind of poses a question for our modeling team in regards to what type of electric residential water heaters we should be including in our modeling for FSSAT.

Next slide, please.

All right, so given those uncertainties discussed in the previous slide, staff are proposing some zero-emission modeling changes to be made for the 2025 IEPR cycle this year.

First, for the South Coast and Bay Area Air Districts, the only modeling changes we propose making for this cycle is to remove the proposed Rules 1111 and 1121 from all of our AAFS scenarios.

We're looking at the CARB state implementation plan, planning to revert back to the 2030 compliance year when modeling their zero-emission space and water heater standard, rather than using last year's more staggered compliance schedule that we had.

Finally, we're also planning to go and use a highly weighted efficiency for any residential water heater replacements happening in our tool. Because FSSAT allows for the installation of either a heat pump or electric resistance water heater, this minor revision here is going to be putting a lot more priority on installing the more efficient heat pump water heater choice. This minor revision also places a more reasonable market perspective for residential water heating replacements, given the upcoming federal standard that was discussed in the previous slide.

Next slide, please.

Moving on to our proposed AAFS scenario characterizations for this year, they are split below into two different tables. The table above looks at our modeling assumptions for the PiCS AAEE and AAFS components that Ingrid discussed in her slides.

And I do want to note here that the PiCS AAFS, it is brought into FSSAT and accounted for in the tool before we do any of our zero-emission modeling. So for PiCS AAFS, we're going to be increasing in scenario numbers as we move across AAFS 1 through 6. For PiCS AAEE gas and electric scenarios, we're going to be using varied uses of Scenarios 3 and 2 across AAFS 1 through 6.

The next table below now considers our zero-emission modeling that is done in FSSAT. We're going to be keeping most of our modeling assumptions the same as we've done in previous IEPR cycles or at least previously in the 2023 IEPR cycle. But there are some changes that are being made to this modeling cycle, I do want to note, with the biggest one being what's happening are statewide existing buildings or the fourth row on this table.

For this row here, we're going to be having AAFS Scenarios 1 and 2 include the modeling of what we are calling a gradual transformation scenario, each AAFS 1 and 2 have different versions of the GT scenario. AAFS 3, we're going to be including the modeling of CARB's Scoping Plan scenario, which I'll provide more detail on in the next slide. AAFS 4 would include a concept of modeling CARB's zero-emission space and water heater standard. And then AAFS Scenarios 5 and 6 would include modeling beyond CARB's standard. Also, look at the additional end uses and fuel types shown in the first two rows of this table.

We also have some replaced adoption percentages shown in this row, but I'm going to be detailing a lot more about that in the next slide.

But looking at the final two rows in this table, we are showing that we're going to be including the modeling for the Bay Area and South Coast zero-emission rules within our AAFS Scenarios 2 through 6. As mentioned in the previous slide, however, we're going to be excluding the modeling of rules 1111 and 1121 since the South Coast rejected those proposed amendments back in this June.

Next slide, please. Excuse me.

So here's just a quick visualization of our proposed 2025 AAFS scenario replace-on-burnout adoption curves that will be applying to statewide existing buildings. I'll give a brief overview.

Replace-on-burnout is FSSAT's way to model the increasing adoption of zero-emission appliances within existing buildings. FSSAT distributes the amount of gas that will expire or burnout each year based on assumed effective useful life. So all in all, these ROB adoption rates are thus indicating the percentage of the yearly gas -- yearly expiring gas appliances that will be replaced with either zero-emission alternative such as a heat pump.

The orange AAFS 1 and the blue AAFS 2 lines shows two different proposals for differing GT scenarios. I do want to note that our current lower bound is AAFS Scenario 1, but we're also looking for any feedback today on how that scenario will be characterized. Any feedback would be very greatly appreciated.

AAFS 1 and 2, we can see that in AAFS 1, we are assuming 50 percent replace-on-burnout adoption occurring by the year 2040. But then in AAFS 2, we now see 100 percent replace-on-burnout adoption occurring by that same year. It's kind of a big difference between our AAFS 1 and 2 GT scenarios.

AAFS 3 now shows the separate residential, which is in dashed red, and commercial, which is in dashed gray, pathways for modeling CARB's Scoping Plan. For all sectors here, we can see that they both 80 percent replace-on-burnout happening by the year 2030. But the residential reaches 100 percent replace-on-burnout by the year 2035, while scenario -- while commercial does not reach 100 percent replace-on-burnout until the year 2045.

AAFS 4 through 6 are all going to be captured in this single green line here to the very far left. In this line here, we see that we're going to be having 100 percent replace-on-burnout adoption occurring by the year 2030. In these cases, again, AAFS 4 is just for modeling CARB's zero-emission space and water heater standard. And then AAFS 5 and 6 will go looking -- will be looking at going beyond CARB's standard to look at the additional end uses and fuel types discussed in the previous slide.

Next slide, please.

So I want to bring up a few notes on some additional updates being made to FSSAT for this IEPR cycle.

First, we'll be planning to make some routine minor updates to some of FSSAT's key input data sets, with one of them being the IEPR baseline energy demand forecast used in our tool. We did not make any substantial or major updates to this cycle for anything for the FSSAT tool, such as adding in any additional fuel substitution to either electricity or hydrogen within the industrial or agricultural sectors.

For this cycle, we're also planning to update our commercial HVAC heat pump heating load shapes that are being used in our FSSAT's hourly module.

We also plan to provide updates to our tool's accounting of PiCS AAFS as they're brought in to develop our overall AAFS scenarios.

Lastly, we're also planning to maintain the same technology assumptions that were used in the last year's 2024 IEPR update cycle. This includes using the same assumptions for the technology sets of both the gas appliances currently in buildings, as well as the electric appliances that will be available to replace those gas appliances as they burn out.

Next slide, please.

To round off today's discussion, I want to just kind of briefly bring up an update on the CEC's heat pump tracking efforts.

So CEC staff currently have an unofficial heat pump estimate for California, which is current as of quarter two this year. This estimate is currently between 1.7 million and 1.9 million heat pumps, but again, it is still being finalized. Overall, though, there's been a good increasing effort in the HEC-wide (phonetic) efforts to track space and water heating equipment, with a particular focus on heat pump technologies.

We're looking at some existing data sources. One that I'd like to note is that CEC staff have been able to use the California Energy Data and Reporting System, or CEDRS, Dashboard Database to be able to help with analyzing programmatic-based heat pump adoption.

CEC is also currently developing energy data collection regulations, also known as our Phase 3 rulemaking, to assist with tracking both space conditioning and water heating equipment. Comments were received for this rulemaking last week, and I've also included a link to the rocket that goes out if you want to see any additional information on those regulations -- oh, sorry, on the rulemaking.

Staff are also planning to be able to leverage advanced metering infrastructure, or AMI, data in the future, be able to also help us out with tracking homes that are installing heat pump technologies.

CEC staff are also in the process of developing a heat pump tracking dashboard, which would be able to provide quarterly updates, and expect it to be released within the next few months.

Finally, we are planning to be able to use the latest heat pump estimate for use in our 2025 IEPR analysis this year.

Next slide, please.

That's the end of our presentation. My contact information can be found here at the bottom of the slide if you have any questions about the modeling we just discussed today.

With that, I think we'll open up to questions.

Thanks, Ethan, and I just wanted to say thank you, Ingrid, to both of you for all the information. I think it will be helpful. I mean, I benefit from a lot of internal conversations on these things. Could you please help just at a 30,000-foot level how the team is thinking about the uncertainties and how to kind of keep the analysis warm as long as possible to finally choose, you know, the specific scenarios? Maybe, Ingrid, you and Ethan can just comment on how you're thinking about capturing uncertainty as we move forward?

MS. NEUMANN: So, I mean, the overall biggest impacts of the uncertainty are probably for Ethan's portion because that includes existing buildings, right, after 2030.

On our side, we're looking at including scenarios that include what we think, at the time when we finalize this at the end of next month, what federal standards are not preempted that would still be included; right? We can build scenarios that include those versus might not, just as a sensitivity, just kind of get some bounds on that. The impacts there probably won't be quite as large as what Ethan will see.

And then, of course, we also are looking at that situation where perhaps the zero-emission standards aren't in place 100 percent in 2030, but it's just having that sensitivity of where they're not in place and where they're fully in place as far as the programmatic inputs.

And I think the rest is fairly carefully dealt with going across the Scenarios 1 through 6. And then there's simply the possibility that rather than choosing Scenario 3 as a planning scenario for AAEE or PiCS AAFS, it could be a different scenario if the, you know, if whatever perspective that particular forecast is to look at leans in that direction.

So then I would say the biggest piece is how to deal with those huge impacts for heat pumps and HVAC; right?

VICE CHAIR GUNDA: Yeah. Thanks Ingrid.

And Ethan, before you jump in, I think, part of the, at least the conversations that we've been having is, especially on some of the SIP, you know, Program and, you know, some of the Air District programs and uncertainty around that, that could translate into several, you know, several hundreds of megawatts of capacity.

Could you just also comment on just directionally, based on where we are today, which parts of that seem to be the biggest movers for you?

MR. COOPER: I think when looking at comparing like the Bay Area and South Coast rules versus the CARB zero-supply standard -- zero supply -- zero-emission space and water heating standard, it would have to be the CARB standard that would be the biggest component of those two or those three components there. And I know that we are -- the big modeling change for this year is changing what we were looking at for modeling an AAFS Scenario 3.

In previous IEPR cycles, we've been looking at modeling CARB zero-emission space and water heater standard in that scenario, and then in Scenarios 4, 5 and 6. With this cycle, we're changing it to be looking at modeling CARB Scoping Plan, which has adoption occurring in more of a less aggressive rate. Like we see the 80 percent replace-on-burnout happening by 2030 for all sectors, but the residential does not get to 100 percent until 2035, and then commercial 10 years later. Kind of the biggest modeling change for those two, at least for Scenario 3.

And then also for more of the local side for the South Coast AQMD, as we mentioned earlier, their Rule 1111 and 1121, we'd previously been modeling that in, I believe, Scenarios 4 and above, but now we're not including those in any of our modelings for this cycle since they were rejected by the board in June. That's kind of how we're treating the certainty on that side.

And then with the CARB zero-emission space and water heater standard, going back to more of the 2030 compliance year for modeling that standard where, in the last IEPR cycle, at least for 2034 update, we had a more staggered schedule that followed more land with going on with the Bay Area and South Coast. So we had some adoption happening a few years earlier for certain water heater -- or either water heating or space heating, for res or commercial.

VICE CHAIR GUNDA: Yeah, Nathan, I also see Commissioner McAllister here.

And just before I pass it to him, I think it's just, you know, good for it as we move forward through the analysis and get through the adoption phase. I think it's also helpful for, you know, the workshop attendees and the public to understand, you know, these variations. Depending on which one, which uncertainty it is, it's also a certain 8760 profile; right? And then that profile has direct impacts on the build out.

So I think it will be helpful for us to emphasize to the previous discussion on how, you know, HD/MD, like, you know, heavy-duty, medium-duty vehicles require a completely different set of distribution upgrades and corridors that's different. So I think for us to elevate that nuance in the final workshops would be really helpful, I think, for the public.

So with that, I'll pass it to Commissioner McAllister.

COMMISSIONER MCALLISTER: Thanks Vice Chair. Super helpful.

Sorry, I was about an hour late here. I'm down in San Diego and there's a lot going on I got today. But pretty familiar with the topic, certainly, and really just appreciate you, Ingrid, and you, Ethan, and the whole team behind you. There's just a lot of -- this is a lot of detail. I mean, you know, end use, by the nature of end use analysis, you know, we're talking about a lot of relatively small devices. Even we're talking about HVAC, and even vehicles in the grand scheme, even though those are large for individual customers, large loads.

Let's see, I guess, so I really appreciated the Vice Chair's question about sort of where the uncertainty lies, you know, particularly contrasting previous iterations of the forecast with this one.

And I have to say, you know, we've seen, you know, the knees knocked out from under some of the initiatives that, last time, you know, previous IEPR cycles seemed to have forward momentum. The affordability conversation is really, I think, taking a little bit of oxygen out of the room for those scenarios. And so, you know, certainly understand with the setbacks to the zero-emission space and water heating rules and the South Coast, that some retooling of the scenarios is logical and necessary. So appreciate that.

I guess I'm kind of wondering, you know, you, since, you know, you both have been and your teams have been delving into this in a lot of detail, and we have the whole, you know, federal conversation, also, in the background, hopefully not in the foreground, but who knows, you know, what's your sense of sort of the uncertainty bars around even our choosing a scenario or even, you know, sort of where we are going to -- complicating choosing sort of what we actually use in the final forecast?

I just ask because I remain hopeful, you know, even though we're not going to have sort of regulatory, you know, minimum standards and force those into the market that really, you know, we all know that's the most direct way to get where we need to go in terms of like, you know, full adoption of heat pumps, you know, and other technologies, but heat pumps in this case.

But also, there's a fair amount of market momentum building just out there in the world for heat pumps, like they're a better product. And, you know, certainly where you have cheaper electricity, you know, in (indiscernible) and the POU and Irrigation District service territories, you know, it's kind of a no brainer. But even where you don't, you know, in IOU territories done right, you know, and certainly where people aren't as price sensitive, heat pumps have a lot of advantages and people are tuning into those.

So I guess I'm kind of just wondering, you know, what's your sense of the wideness of the uncertainty sort of road, you know, the scenario around all these scenarios and sort of the job ahead of you to get to the final forecast versus previous years?

Oh, I think you're muted.

MR. COOPER: You're on mute, Ingrid.

MR. GEE: Ingrid, you're muted.

COMMISSIONER MCALLISTER: There you go.

MS. NEUMANN: I had a little cough, so I had to mute myself.

COMMISSIONER MCALLISTER: Happens to the best of us. No worries.

MS. NEUMANN: In any case, I'll say what I think, though Ethan's, you know, obviously doing the work there with the actual --

COMMISSIONER MCALLISTER: Mm-hmm.

MS. NEUMANN: -- zero-emission standards. It's very extreme to have, you know, everything happen in 2030, right, versus nothing. Those are the error bars; right?

COMMISSIONER MCALLISTER: Yeah.

MS. NEUMANN: We do see the momentum in the market. It's hard to quantify it. With the heat pump tracking, perhaps we can get a trajectory where there is a scenario that is somewhere in that range of 1 through 3 or maybe, you know, that is what we would expect to have occur because of this natural adoption and the fact that people are realizing that these are better products, for example, right, and without having additional, you know, standards like the CARB set in place. So I think that would ground that kind of scenario with data in a way that we can't quite do now, I think; right?

COMMISSIONER MCALLISTER: Well, interesting. And the thing I forgot to mention is the impacts of the legislation that passed earlier this year preventing local governments from doing reach codes. And, you know, the many local governments that are wanting to promote heat pumps in their territories, you know, require them on a retrofit or do new measures like that. But now, you know, in residential space, they've been prohibited from doing for one code update cycle, which is just very unfortunate.

MR. COOPER: Yeah, and I want to agree with Ingrid about, you know, our current AAFS Scenario 1 is, you know, like 50 percent adoption by the year 2040. That's like our current idea of what could be the most conservative scenario in terms of our zero-emission modeling. But once we can go get better data on heat pump, you know, installations throughout the state of California, it would be a good way of having a more data sound version of AAFS Scenario 1 and a good data sound lower bound.

COMMISSIONER MCALLISTER: Great. I really, really appreciate that. So I guess I'm hearing we need to kind of light a fire under that regulatory package to get those data rules updated so we can collect that data and give you guys what you need?

MS. NEUMANN: Yes, please.

COMMISSIONER MCALLISTER: Yeah, exactly.

Well, I think I think that's it for me right now, but thanks for all the work and presentation. Really, really foundational, so appreciate it.

MR. COOPER: Thank you.

MR. YOUNIS: All right. We'll go to Q&A. We have two questions. One is from Josh Spooner from E3.

> "Are the zero-emission appliance standards described for AAFS 3 through 6 allowed under AB 306, the moratorium on residential building codes through 2021?"

We've already answered these in the Q&A box, but I'll read them for everybody's benefit.

> "When discussing our scenarios with CARB, they did not raise this as an issue. The AQMD's rules likely do not fall under AB 306 either."

Ingrid added,

“AB 130 affects Title 24, including the building energy efficiency standards, and does not affect CARB’s emission standards.”

Jenny Conde from PG&E writes, “Can you clarify what inputs are included in the routine update of data for FSSAT?”

And we had responded that,

“They include updates we do for every forecast, like updates for the baseline forecast, building forecasts, and floor space forecast.”

And that’s all I have.

Back to you, Quentin.

MR. GEE: All right. Well, thanks to Ethan and Ingrid for their presentations.

Next up, we have discussion on behind-the-meter, solar, photovoltaic systems, and energy storage. First, that’s going to be Bobby Wilson and Mark Palmere. Before going into the forecast directly, we’re going to have Bobby present on historical behind-the-meter insights.

Bobby?

MR. WILSON: Thank you, Quentin.

Hello, everyone. Good afternoon. My name is Bobby Wilson, and I am a Distributed Generation Specialist in the Demand Forecasting Unit. And my presentation is on behind-the-meter distributed generation insights.

Next slide, please.

Okay, before we begin, here is a list of acronyms and initialisms that I'll be using throughout my presentation.

Next slide, please.

First, I'd like to talk about the relevance of the data I'm presenting. The historical behind-the-meter PV and storage capacity estimates are important inputs for several models and processes. Historical PV capacity is used to calculate behind-the-meter PV generation, and that feeds into our hourly load model, as well as the sector models, which forecast consumption. And then both of these, PV and storage capacity, these are both inputs to our dGEN model, and that forecasts PV and storage adoptions -- storage adoption.

Next slide, please. Okay.

And as we'll see in our coming slides, our key finding this year is the significant increase in storage. And that increase is a result of increased attachment rates, and that is a result of the NBT, but we'll see that in a couple of slides.

And then on the PV side, our findings pertain to application volume. The number of applications in 2024 approaches 2021 levels. And the growth in PV is being driven by similar growth rates in the PG&E and SCE territories.

Next slide, please.

So we'll first take a look at PV adoption trends.

Next slide, please.

Here is our statewide capacity as of December 2024. The historical numbers are in line with our previous historical estimates and forecast cycles. And then notably, as you can see, the system count has broken 2 million for combined residential and non-residential systems.

Next slide, please.

This is graph of PV capacity in the CAISO transmission area. In the table to the left, you can see the increases in capacity since 2014 in five-year increments, and we have them broken out for each IOU, and then all together in the CAISO transmission area. Overall, there was a nine percent growth rate in capacity from 2023 to 2024. And as we said in the key findings, that's primarily driven by the growth in PG&E and SCE plan areas. They both grew at a 10 percent rate in the same time period from 2023 to 2024.

Next slide, please.

We'll now look at storage adoption trends.

Next slide, please.

Okay, here we have the behind-the-meter storage statistics for the entire state. Residential storage capacity's growth rate has outpaced non-residential storage capacity for several years now. Last year, we saw an even bigger increase than usual in residential storage, a 54 percent increase.

We can also see that we're nearing 250,000 storage systems. I think it's safe to assume that we have hit that number already in 2025, but this data just goes through December 2024, so we did not put that on the slide.

And then also in the table to the left, you can see nameplate capacity in megawatts and the energy storage in megawatt hours, as well as the count of systems for residential and non-residential systems.

Next slide, please.

And here is the CAISO transmission area behind-the-meter storage capacity and count and statistics. The table to the left here also has megawatts for nameplate, megawatt hours for energy storage, and broken out by IOU, and then the total for CAISO. And one thing I wanted to highlight was the increase in storage capacity by IOU. So PG&E had a 60 percent increase in storage capacity, followed by SCE at 50 percent, and then SDG&E at 40 percent. So significant increases across the board.

Okay, next slide, please.

All right, so the data on the next two slides comes from the CPUC, so I'll take a moment to thank the CPUC for sharing that data with us. They've been coordinating with us for the last two years with this specific data set, so much appreciated.

This chart clearly shows the effect of the NBT which was adopted in quarter two of 2023. The attachment rate for the first two quarters of that year was below 15 percent. It has steadily increased each quarter, reaching 77 percent by the fourth quarter of 2024 and driving the increase in storage capacity that we saw on the previous slide in the CAISO transmission area. In December 2024, the attachment rate reached 80 percent, and we will continue to track attachment rate as we prepare our forecast and see if it goes above the 80 percent into the 90 percent range.

Next slide, please.

This chart shows application volume by quarter as well as a trend line. A couple of notes.

First, again, this data is from the CPUC.

Secondly, this trend line was trained on historic data from January 2017 to December 2022, so you can see on the chart the large surge in applications in quarter one and quarter two. The trend line is not affected by that surge in applications which happened with the NEM 2.0 expiration.

So keeping that in mind, this chart shows that the application volume has not grown at the observed rate before quarter one 2023 surge in applications. So based on that growth rate from 2017 to 2022, the current application volume is lower than expected. However, the actual volume in quarter one of 2024, for example, was within a couple thousand applications of quarter one 2021. So that’s just the actual volume versus the projected growth rate.

And then we started tracking this application data last year. There are several reasons to track application data. I’ll just highlight one of them and then talk about why we’re still tracking it.

So last year we used the application data to calibrate first year projections in our forecast to account for the large number of NEM 2.0 applications that were still being interconnected, So that speaks to that surge you can see on the chart. Those systems were still being interconnected last year.

And then similarly this year, we wanted to track application data to see if there will be another surge in behind-the-meter PV adoption due to the ITC elimination. So we will continue to coordinate with the CPUC and track the applications.

Okay, next slide, please.

All right, that is the end of my presentation.

Thank you to everyone. And now my colleague, Mark Palmere, will give this presentation.

MR. PALMERE: Good afternoon, colleagues and active participants. My name is Mark Palmere and I am the Distributed Generation Adoption Lead at CEC. And today I'm going to talk about inputs and assumptions for this year's distributed generation forecast.

Next slide, please.

Before I go into detail, here's a list of acronyms and initialisms that I'll be using on slides in this presentation.

Next slide, please.

First, let's look at the forecast as a whole. The forecast framework has not changed since last year. However, I will briefly go over it for those who are new to it or need a refresher.

Next slide, please.

Here are the technologies we forecast as part of distributed generation, solar PV, energy storage or batteries, and other self-generations such as fuel cell, gas turbine and wind turbine energy. And the metrics we use are capacity and energy.

Next slide, please.

Next, let's look at how the forecast has updated.

Next slide, please.

There are a few new drivers of forecast uncertainty this year. First, the elimination of the Investment Tax Credit, or ITC, will lead to an effective increase in solar cost and it will be incorporated into this year’s forecast. Meanwhile, due to widespread uncertainty around their implementation, tariffs are currently not expected to be included in the forecast.

PV and storage costs continue to be determined by NREL, the National Renewable Energy Laboratory’s Annual Technology Baseline, which forecasts future costs based on technological advances and research and development investments.

The table on the right shows how they differ in each scenario. In the conservative scenario, technology remains comparable to today while research and development investment levels decrease. In the moderate or expected level, current innovations are more widespread and investment levels remain constant. And in the advanced scenario, currently theoretical innovations become successful and investment levels increase.

Do note that we are actually using last year’s ATB. Because of all the uncertainty, NREL has not yet published this year’s ATB forecast, so we’re unable to incorporate it into this year’s forecast, but we’ll incorporate it as soon as we can moving forward.

Next slide, please.

As mentioned in the last slide, tariffs will not be considered in our forecast beyond what has already affected costs. This is due to the widespread uncertainty surrounding them, both in the short term and in the long term, the frequent changes in their announced values and the unclear level of enforceability of these announcements, which creates a lot of uncertainty.

It’s not clear how companies would adapt to new tariffs as companies rely on raw materials from China, especially for the storage component. But do note that much solar is manufactured in the U.S. and thus less likely to be as impacted by tariffs. The U.S. is capable of manufacturing over 26 gigawatts of solar annually, and that’s about 65 percent of the total domestic capacity that was installed in 2024.

Moving forward, right now it’s unclear how that number will change, especially if, potentially, demand for solar will go down due to the decrease in ITC. It may be more easy for it to meet the demand. So basically all the uncertainty is why we’re not making any, not incorporating any impacts at this point.

Next slide, please.

With that in mind, here are the four adoption scenarios we do plan on incorporating this year.

The low case will use conservative capital expenditure costs and an eliminated ITC.

The mid case is moderate CapEx costs and an eliminated ITC.

And we're also introducing a mid-plus ITC scenario, which uses the mid case assumptions, along with a reinstituted ITC in 2030 to account for the possibility of a new administration bringing it back. We are adding it to the mid case because we figure that's the most likely case that would constitute a return to the ITC as opposed to cheaper solar in the high case where it would be considered perhaps less necessary.

The year 2030 is somewhat arbitrary. It's not based on any current policy or legislation. It's just thinking about when might be like the most expected time for it to return based on the potential new administration and how long it would take to implement such a -- re-implement such a policy. And so we're calling like the most likely time. But, as I said, it's not -- right now, there's no policy to make us believe that we're just including it to account for the possibility and be prepared for that.

And then in the high case, we're using advanced CapEx costs and no ITC, but we are also adding storage retrofit as a result of NEM contract turnovers. And that means that when NEM customers are scheduled to shift to NBT, we are going to model them adopting storage at the same rate that NBT customers currently pair their solar with storage. And note that this is relying on the current designation of NEM customers switching to NBT after 20 years.

Next slide, please.

And finally I'd like to share some results of a test we did that will estimate the effect of the ITC policy shift on our PV forecast.

Next slide, please.

Staff tested the effect of the ITC elimination using our dGEN model by keeping inputs unchanged from the 2024 IEPR mid case with the exception of ITC-related inputs. But please note that this is one of many changes to the 2025 forecast and those results will be presented in October as part of the full forecast.

Next slide, please.

A key driver of adoption is max market share, which is influenced by payback period. Staff was interested to know how these variables would change without the ITC, so we performed a simplified modeling exercise with CPUC's NBT model to cross-check our findings for IOU planning areas. As you would expect, payback period rises with the discontinuation of the ITC by about two years.

But by 2035, payback periods are identical again as that is when the ITC was set to expire in our 2024 IEPR forecast. So the only differences are in the years between this year and 2035. Everything else is the same. But max market share does near 40 percent in that forecast by 2033 while it gets as low as 25 percent in the run without ITC. I believe it’s at its lowest in 2027.

Next slide, please.

With that in mind, let’s look at the results. In the test run, installations dropped by about 40 percent annually until 2030. This entire decrease comes from retrofit installations as the Title 24 installations will remain constant.

Next slide, please.

Looking at it from a cumulative forecast perspective, in the 2024 IEPR forecast, 55 percent of the added PV capacity came from retrofits. But without the ITC, that share drops to 50 percent. And then Title 24, the new construction remains constant in both scenarios because it’s compliance-based, not economic-based.

And then just as a final reminder, please note that this is the test of the effect of the ITC change and is not our 2025 forecast. So please do not share these numbers as our forecast because that is still in progress and will be presented later.

Next slide, please.

And then finally, some quick comparison tables. So cumulative PV capacity is reduced by over 10 percent in the early 2030s, but is down to about 5 percent in 2040.

And then, meanwhile, looking at just the capacity added within the forecast period, which is the column on the right, in other words, we're discounting historical capacity, that gets as high as 28 percent before dropping to about 12 percent in 2040.

And then when looking at the growth rate, it's about five percent with the ITC until 2033, and then a little over one percent after the credit is phased out.

And in our new test run, it's consistently close to about 3 percent per year, but actually slightly lower post-2034, even though by that point, the model is -- adoption is beginning to recover from the ITC elimination.

But overall, it's a little more consistent than last year's forecast, but less cumulative capacity.

Next slide, please.

This concludes my presentation. Thank you all for listening. I'll now hand it over back to the dais for questions and comments.

VICE CHAIR GUNDA: Yeah, thank you, Mark. I want to just make sure that Commissioner McAllister is still available and he might have any questions.

Commissioner McAllister, would you want to start?

COMMISSIONER MCALLISTER: Yeah, let's see. I'm still kind of collecting my thoughts, actually. But you know, obviously, we're just seeing a lot of headwinds in all sorts of different ways hitting the demand side and small-scale deployment. And it's creating, as we've heard, you know, as we've heard on the efficiency fuel switching side just now, also, it's kind of cramping our style in terms of how we chart a path to our goals.

You know, I guess I found you're -- the analysis like not surprising at some level, but also a little bit positive because I kind of thought maybe the ITC going away would be a little bit worse and sort of the stability out in the out years is kind of a good sign.

In your interactions with the solar community, are you hearing a pretty consistent message or are you hearing, you know, a cacophony or somewhere between or what? Like I guess I'm just kind of wondering what the zeitgeist is out there, you know, as we try to sort of -- we got maybe a (indiscernible) on our back, you know, on a few different fronts, but still some room to leverage our market power in California to be a good -- you know, an influence for good.

So I guess I'm just kind of wondering what, you know, what messaging you're kind of hearing from the various players in the solar market.

MR. PALMERE: Yeah, we're hearing, I would say, we're hearing kind of a lot of different messages, because it seems like there is, that's kind of the key word, is there is a lot of uncertainty about what is going to happen, especially talking to utilities who have their own forecasts. Some are including tariffs, some are not, and then there's all sorts of different values. So it's just, just due to the uncertainty, there's kind of -- unfortunately, we're hearing things in a lot of different directions.

But, yeah, I would say like overall, I think the message is definitely like concerning. I mean, these are not favorable for solar adoption, but I think there is some, like some optimism, especially in the long term. I think that it could have perhaps less of an impact than feared. But, I mean, with all the uncertainty, I would certainly not say that confidently, as more of like a goal that solar is like not going away, but it's still going to be there. But, yeah, this is overall a negative, I guess.

COMMISSIONER MCALLISTER: Are there any particular sort of positive spots or business models or kind of subsectors within solar that, that seem more hopeful?

MR. PALMERE: Not subsectors in particular, but I know there’s definitely some talk from some like manufacturers and installers who are kind of using it as an opportunity to see like where they can cut costs and like potentially, like especially in terms of like soft costs, making it a little more affordable to kind of cushion the, the blow from the ITC. So there’s definitely some like positive momentum in that direction to try to --

COMMISSIONER MCALLISTER: So --

MR. PALMERE: -- make it less of a financial shock when the ITC does go away. But, I mean, that’s why. And, yes, and that's --

COMMISSIONER MCALLISTER: Yeah.

MR. PALMERE: -- we’re definitely going to look at the interconnection data when we get it, because we are able to. The CPUC’s DG stats website provides cost data. So that’s something we’re going to be looking at to see what --

COMMISSIONER MCALLISTER: Interesting.

MR. PALMERE: -- trends we can find on that end.

COMMISSIONER MCALLISTER: So folks who come out the back end of this may be stronger and a little more disciplined. I mean, I guess that’s maybe a silver lining.

MR. PALMERE: That’s like an optimistic way of looking at it, that it could make solar better, more viable in the long run. But --

COMMISSIONER MCALLISTER: Yeah.

MR. PALMERE: -- I mean, yeah, there’s a lot that still could be seen.

COMMISSIONER MCALLISTER: I guess the other question would be just about attachment rates for batteries. And, you know, that’s obviously something we really want to happen. It helps with, you know, reaching our low flex goal. It helps in all sorts of ways to bolster the grid. I mean, I imagine there’s some optimism there because, I mean, I guess, what can you say about the attachment rates?

MR. PALMERE: Yeah, they’ve consistently been going up, basically, ever since the switch to NBT. I mean, yeah, they were kind of in around the 10 to 20 percent range before. Under NEM 2.0 and under NBT they’re -- they’ve -- at the end of last year, they were approaching 80 percent. And I think, obviously, the elimination of the ITC will make -- it will make it more expensive, but it will still -- everything else will stay the same in terms of the positive incentives for installing storage.

So we expect to see, continue to see high attachment rates at this point. But, yeah, again, that’s going to be kind of the theme is that something we’re going to have to check to see what’s -- what we’re actually seeing in the real world. But we’re definitely optimistic about attachment rates. They've been consistently higher than even we'd been really expecting a couple of years ago --

COMMISSIONER MCALLISTER: Interesting.

MR. PALMERE: -- since we thought. And so that's definitely a positive sign.

COMMISSIONER MCALLISTER: Yeah. Great. I mean, I love the cost information. I mean, I hope DGStats, you know, it's not probably exactly what's actually happening out there in the marketplace, just because that's reported data, but it's the best we've got by far. So it will really interesting to see how the cost numbers come through for both solar portion and battery portion. Do we get that disaggregated?

MR. PALMERE: We don't.

COMMISSIONER MCALLISTER: Okay.

MR. PALMERE: But we're kind of able to isolate where -- or do our best to isolate (indiscernible).

COMMISSIONER MCALLISTER: Yeah. Okay. All right, well, that's it for me. Thanks so much, Mark. That was a great presentation. Really appreciate all your work digging into this. Thanks.

MR. PALMERE: Thank you, Commissioner.

COMMISSIONER MCALLISTER: Thanks.

Back to you, Vice Chair.

VICE CHAIR GUNDA: Yeah, Commissioner.

Mark, Bobby, thank you so much for the presentations. Let me kind of jump into just a couple of questions that Commissioner Mark -- Commissioner McAllister touched on.

Can I just get it, get a confirmation that on the tracking interconnection applications, Bobby, that you mentioned, is that for only behind-the-meter solar or is it combined, even for hybrid system and paid systems? How do we count those applications?

MR. WILSON: You mean, is it for -- when you say hybrid, you mean storage and solar?

VICE CHAIR GUNDA: Yeah, yeah, paired storage.

MR. WILSON: Yes. Yes, it’s everything.

VICE CHAIR GUNDA: So basically, like we have a reduction in total applications of behind-the-meter?

MR. WILSON: We have a reduction in the anticipated volume, like the growth, but like the 2024 volume is similar to 2021. But, yes, it is not growing at the same rate it was before the NBT (indiscernible).

VICE CHAIR GUNDA: Thank you. The other one, just on the paired versus standalone, just the last two years’ worth of information, that, you know, I just wanted to make sure as we move in the attachment rates have gone significantly to almost 77 percent now. So what about retrofits? Are they systems where in existing solar and just applications coming for just adding the storage, are those applications tracked somewhere?

MR. WILSON: We actually -- are those applications tracked somewhere? Not exactly. But we did notice a significant number of retrofits this year by just digging through the interconnection data and forming an analysis. So our hope is to perhaps get those applications tracked more systematically next year. But, yeah, we are seeing, for sure, systems, standalone systems, previously standalone systems adding storage. And that is something that we are hoping to track next year more systematically.

VICE CHAIR GUNDA: Got it.

And this is maybe just to Mark, just want to confirm, has there been any shift in the average size of the application, like the unit size, since the NBT?

MR. PALMERE: I don't believe so. Bobby's actually worked with the interconnection data a little closer.

I don't know, have you noticed any trends?

MR. WILSON: I have not notice any trends. A slight uptick, but not anything that would be significant.

VICE CHAIR GUNDA: Yeah.

MR. PALMERE: We can definitely get the -- some more precise numbers over to you after this.

VICE CHAIR GUNDA: Yeah, Mark, let's plan to put that out, like during the final presentations on this. I think a couple of pieces are, it will be really helpful to track the nature of applications, how they're changing. Obviously, the kind of paired systems is a proxy to that. But just a few trends on how the types of applications are changing, or the, you know, the overall capacity per application, those will be useful insights to have; right?

And then also for -- and the last piece, just want to make sure, on slide number 12, Mark, you have, of your presentation, the installations dropped by 40 percent of 2024 IEPR until 2030. So want to just understand, you have a significant drop with the no-ITC, but the 2024 IEPR drops even further down. Is it just that we -- you know, because of the lower market penetration, it stays longer? Is that the issue?

MR. PALMERE: We --

VICE CHAIR GUNDA: Or is that kind of the contributing factor?

MR. PALMERE: Yeah, that, I think that we've considered that to explain the difference in the 2024 IEPR when the ITC was set to expire next decade that the market would be more saturated by then, so it would be even more of a significant drop than it happening next year, so that's the only reason.

VICE CHAIR GUNDA: Got it. That makes sense. Thank you. Yeah, no further questions.

And again, to just Commissioner McAllister's point, really appreciate it. I think the amount of work that went in the last, you know, five years on continuing to enhance the models to not just the both of you, everybody who presented today, to make it more rigorous, more accessible, really helpful. And also just acknowledging the limitations in data to the public. So, you know, where the variations are coming from, it's always a really good thing, you know, the transparency, you know, creates trust and stuff. So super helpful with that.

With that, I'll pass it to Quentin, unless Commissioner McAllister have any additional questions. Okay, to Quentin.

Thank you, Bobby. Thank you, Mark.

MR. PALMERE: Thanks.

COMMISSIONER MCALLISTER: Thanks.

MR. WILSON: Thanks.

COMMISSIONER MCALLISTER: Nice teamwork. Appreciate it.

MR. GEE: Great.

MR. PALMERE: Thank you.

MR. GEE: Thank you. Thank you both.

All right, so we do have one question, Laith.

Did you want to that?

MR. YOUNIS: Yeah. James McGarry asks, "Do you have visibility into how much of the new behind-the-meter storage solar is being installed under the grandfathered NEM 2.0 tariff versus the NBT? And does the dGEN model account for that distinction by tariff type in the historical data and the roll off of new NEM 2.0 installations when forecasting future solar storage adoption?"

Bobby, thank you for answering. We use the application data provided by CPUC to determine how much capacity is being added from NEM 2.0 versus the NBT. The dGEN model forecasts NBT adoption. We account for NEM 2.0 installations exogenously.

If anyone else has further comment? If not, back to you.

MR. GEE: I think there's one remaining question I just caught in the open box, the fraction of solar interconnect requests that end up getting installed. Do you have any insight into that, anybody?

MR. WILSON: Yeah, we do not have an exact number at this time. That's something that we could potentially figure out. But, yeah, I wouldn't have that number at this time, but could get it in the future.

MR. GEE: All right.

MR. PALMERE: Well, yeah, just to add to that, I would say that, yeah, so the applications, it's an interesting comparison. But, yeah, for like, for the interconnection data that Bobby works with, that's based on installation, so we're not like assuming things will be installed.

But just to clarify. Thank you for your question.

MR. GEE: Great.

MR. YOUNIS: Okay.

MR. GEE: Maybe just one final comment to both of you, just to kind of -- or maybe a pitch or acknowledgement. Your team did do the -- did do a NEM turnover analysis in the demand scenarios project. So for folks that were curious, or for Vice Chair Gunda, who's curious about the NEM contract turnovers, although that's something your team is definitely tracking, we did actually do a scenario in that. And so that's something that we're going to be kind of -- you know, we're kind of well-equipped to begin thinking about if we begin noticing that pattern. I would think that your team would. You know, that's kind of one of the benefits of the demand scenarios work is to be able to kind of test out new approaches. So yeah, it will be interesting once we can get more data on it.

All right, well, thank you, Bobby. And thank you, Mark.

I think we're, the Q&A is all done. So I'm going to go ahead and hand it over to Stephanie. Thanks to all the presenters and the folks on the dais and, of course, the IEPR Team.

Moving on to public comment. Thanks, Stephanie.

MS. BAILEY: Thanks, Quentin.

Okay, so we're going to be moving on to our public comment period. Just as a reminder, it's one person per organization that can comment and those comments are limited to three minutes per speaker. And a reminder that while we welcome your comments, we won't be responding to questions during the public comment period. This notice that we have posted provides information on how to contact us with any follow-up questions that you may have.

If you would like to make a comment and you're on Zoom, you can use the raise-hand feature to let us know and we'll call on you and open your lines so that you can make those comments. For those on the phone, you can dial star nine to raise your hand and star six to mute and unmute your phone line and we'll do that from our end.

So we're going to go first to Zoom. And it looks like Kevin Barker, let me go ahead and unmute -- or allow you to talk and you'll have to unmute on your end.

MR. BARKER: Can you hear me?

MS. BAILEY: Yes, we can hear you.

MR. BARKER: Thank you so much, Stephanie. Good afternoon. Kevin Barker with SoCalGas.

First off, I'd like to thank staff for the countless hours put into researching and developing the price forecast and load modifiers.

While Vice Chair Gunda noted the inherent uncertainty in forecasting. Some of the assumptions have greater impact on the end result than others. For example, in the AAFS scenarios, Scenarios 4 through 6 will likely produce similar outcomes for both electricity and natural gas consumptions. Scenarios 2 and 3 will also be somewhat similar, and Scenario 1 will be a bit of an outlier.

So I haven't seen the outcome of the results, but I might venture a guess that the difference between Scenario 1 and Scenario 2 may be greater or equal to the difference between Scenario 2 and Scenario 6. And yet five of the six scenarios are predicated on regulations that have not proven to be legally binding. To have such a high impact on gas consumption based on regulations that haven't been approved or are stuck in litigation seems premature.

Since there's so much uncertainty and such extensive impact from AAFS scenarios on California's energy planning, it's in the public interest to choose a range of six scenarios that fully capture the spectrum of outcomes that could be possible instead of multiple scenarios that converge on a similar endpoint. Ideally, each scenario should be sufficiently differentiated from one another.

Also, there appears to be a lack of a business-as-usual scenario in AAFS, which Ingrid noted is typically Scenario 3 for AAEE planning.

Also, regarding uncertainties and the magnitude of impact, the price -- the electricity price forecast uncertainty slide do acknowledge the limitations. However, they don't allow the public to understand how much of a difference each component could change the outcome. For example, one of the utilities showed roughly a $0.10 per kilowatt hour decrease due to a change in transmission costs. That's close to a 30 percent drop in residential rates. It also noted that the data center impact could reduce the overall cost by one and a half cents per kilowatt hour. Meanwhile, historical prices displayed in the slide indicate a 30 to 60 percent increase in residential rates over the last 5 to 10 years.

So what would be the impacts if wildfire mitigation costs remain consistent or actually escalated? What if data centers chose onsite generation rather than interconnecting to the grid? And what if CAISO's TPP forecast of $30 billion of additional transmission comes to fruition? These prices aren't reflected in the possibilities.

Lastly, I'll be really brief, retail rate forecasting are extremely complex, yet any forecast that is released publicly carries significant weight in influencing public policy and business.

Just that.

MS. BAILEY: Thank you, Kevin, for your comments.

We're going to go ahead and move to our next commenter, CALSSA. You should be able to unmute on your end.

MR. HART: Yes, thank you. Can you hear me?

MS. BAILEY: Yes, we can hear you.

MR. HART: Perfect. Thank you. I'm John Hart, the director of policy for the California Solar and Storage Association.

A couple comments I had on the last presentation, which, first of all, thanks for all the work going into this. The data that was presented on solar and storage adoption is very consistent with the data that we're collecting, what we're seeing in the market with our member companies. Also, the concerns with -- at the federal level, and there's also many concerns at the state level, are definitely making it more difficult to install behind-the-meter solar and storage.

There was a question from Commissioner McAllister, which was, are there any bright spots out there? I can’t remember exactly how it was framed, but the biggest thought that I had is a great opportunity that California has, especially the Energy Commission, Public Utilities Commission, CAISO, are to help create new value streams that behind-the-meter solar and storage are able to access and really using millimeter batteries, especially to respond to price signals, to act as virtual power plants.

There are a lot of untapped -- there’s a lot of untapped capacity and capabilities out there already. There’s a huge room for growth here. And that could be an area where if new value streams open up, it would really help stabilize the future outlook of solar and storage. And then in return, these resources are able to provide, you know, very useful grid services at a cost-effective price.

So I just wanted to make that comment as to, you know, always be giving a plug, I guess, for the abilities of these resources.

Thank you.

MS. BAILEY: Thank you.

Okay, it looks like we have one additional person with their hand up. Jerry Cui (phonetic). Sorry if I mispronounced your name. Well, it looks like you may need to unmute on your end. Jerry, are you able to unmute on your end to give your comment? It looks like no. In the meantime, Jerry, we're going to go to the phone participants today.

So once again, if you are on the phone and you want to make a public comment, you can use dial star nine to raise your hand and star six to mute or unmute your phone line. Give that just a second, if any of our phone participants wanted to make a comment.

Seeing none, I'm going to try to unmute Jerry's line one more time. Jerry, you'll need to unmute on your end to make your comment.

Okay, well, then we're going to go ahead and move to Ben Peters. Ben, you'll need to unmute on your end to go ahead and make your comments.

MR. PETERS: Good afternoon, everyone. My name is Ben Peters. I'm with the organization US Solar.

My comment is regarding front-of-the-meter connected DG resources. I encourage everyone focused on this topic to look to the historical interconnection queues. There was many, many applications. And DG resources applied for under both the WDAT and Rule 21 export interconnection queues. And so there is a good data set of the type and quantity of those resources that had site control as a condition for applying for interconnection. Unfortunately, due to some of the situation at the CPUC in creating the legally-required Community Solar program, little to no of those projects have come online or are expected to come online.

So my comment is that this is a huge missed opportunity for these types of resources. And looking at the queue data is a valuable perspective in seeing the type and quantity of resources that can be available to meet our goals.

Thank you.

MS. BAILEY: Great. Thank you, Ben.

Is there anyone else that would like to make a comment before we turn over to the dais for closing remarks?

Seeing no further raised hands, just a quick reminder that written comments are welcome and those are due by September 9th.

And with that, I will turn things back over to Vice Chair Gundu for any closing remarks.

VICE CHAIR GUNDA: Yes, definitely. Thank you so much. Again, I just wanted to thank all the staff, really helpful information. I think really looking forward to hearing more input. Thank you for all the commentators on some really good points that were made about the uncertainty and the decisions and how carefully we need to make.

And so I really, you know, appreciate all the work done. I look forward to getting written comments and continuing the conversation.

With that, I'll see if Commissioner McAllister has any thoughts.

COMMISSIONER MCALLISTER: Just to reiterate the thanks. This is really foundational stuff. And California, I think, really is the only planning area of the country that, certainly, that digs this deep, but even really takes this sort of comprehensive approach to understand, you know, the ebbs and flows and just the whole landscape across our state and connected to economic development and really sort of begin with first principles to try to understand in a deep way what load is doing.

And as we all know, you know, time matters and we need to get all the -- if we're going to have this orchestra, you know, of millions of devices sound good and, you know, in harmony and not in cacophony, we really need to take this approach and we need to mobilize a lot of stakeholders and use a lot of technology and deploy, you know, devices and business models that work and really put them through the crucible to make sure that they function properly for the long term.

So this is where that process starts. And we have a lot of partners out there to make it work and, you know, working together with Vice Chair on the 7,000 megawatt goal by 2030, understanding load is fundamental to that.

So really appreciate all the work and I think we have the best team on the planet doing this work. So appreciate the workshop today and looking forward to keeping the momentum going forward on this.

Thanks for your leadership, also, Vice Chair. Appreciate you.

COMMISSIONER MCALLISTER: Yeah, thank you, Commissioner. Same to you. You know, I just follow your footsteps a lot of times.

So thank you all for all the work. Look forward to continuing conversations.

With that, I would like to adjourn the workshop. Thank you.

(The workshop adjourned at 3:14 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 31st day of October, 2025.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

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

October 31, 2025