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STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

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RE: Electricity and Gas Demand Forecast	)	

IEPR COMMISSIONER WORKSHOP ON

ENERGY DEMAND FORECAST INPUTS AND ASSUMPTIONS

REMOTE VIA ZOOM

WEDNESDAY, AUGUST 6, 2025

9:00 A.M.

Reported by:

Martha Nelson

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CPUC

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P R O C E E D I N G S

9:00 a.m.

WEDNESDAY, AUGUST 6, 2025

MS. NAKAGAWA: Good morning. Thank you so much for joining. Today, we're having an Integrated Energy Policy Report, or IEPR, Commissioner Workshop on the Energy Demand Forecast Inputs and Assumptions. I'm Sandra Nakagawa, Director of IEPR at the California Energy Commission. This workshop is being held as part of CEC's proceeding on the 2025 IEPR.

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

Throughout the day, there will be opportunities for the audience to ask questions of presenters. We'll have a few minutes after each panel to take audience questions, though we may not have time to answer all the questions submitted. You can use Zoom's Q&A feature to submit questions. You can also look at questions that have been previously submitted and upvote those by clicking on the thumbs up icon. Questions that receive the most upvotes are moved to the top of the queue. Attendees also

have the opportunity to make public comment at the end of today's workshop. Please note that we will not be able to respond to public comments, and those are limited to a maximum of three minutes per person, with one person per organization allowed to comment.

Written comments are also welcome, and instructions on how to provide those can be found in the workshop notice. The deadline for written comments is 5 p.m. on August 20th.

We're now going to turn it over to Vice Chair Siva Gunda for opening remarks from the dais.

VICE CHAIR GUNDA: Thank you, Sandra. Good morning, everyone. Thank you so much for being with us today and for being a part of the IEPR workshop.

As many of you know, the forecasting work of the Energy Commission is an integral and foundational part of its work, which then flows into a number of downstream processes, both at CPUC and CAISO, and becomes really important in terms of understanding how it impacts the rest of the planning process in the state.

I would like to extend my warm welcome to Commissioner McAllister from the CEC and President Reynolds and Commissioner Baker, who are joining us today for this workshop. I also want to provide my sense of gratitude and a big thanks to both the IEPR team for organizing today's

workshop and the EAD staff for their dedication, the Energy Assessment staff for their dedication to this important planning process.

As we continue to evolve the forecasting to meet the needs of the times, it's really important to again reiterate how the forecasting really impacts some really important downstream products, such as resource adequacy at CPUC, both the IRP and the transmission planning, but also provides input into broader work for California Air Resources Board, but sees its work in demand scenarios and further resource planning and long-term transmission planning as well. So the work that the Energy Commission does on demand forecasting and demand scenarios informs a lot of critical processes all the way from generation to transmission to distribution. It's really important for us to continue to make sure that the forecast reflects a load to make sure that we have reliable supply and we have the timely build-out that we need and the procurement decisions are driven through that, but also making sure that we do not overestimate uncertainties and then overbuild, which will cost the ratepayers.

So today's planning efforts are continuing to come in a time of growing uncertainty. We are now navigating an evolving climate change. That's something that we have been trying to incorporate over the last

decade, but also now compounded by both shifting federal policies from regulation to tax credits and tariffs and rapid technological advancements like AI and some emerging loads such as hydrogen and such. So as we think through this it's really important to recognize the continued need for refinement of the forecast, and I want to commend the CEC staff for making a number of improvements all the way from making the annual forecast to an hourly forecast, incorporating better and better information for behind-the-meter solar production, storage dispatch to modify the forecast adequately, and continuing to put in the impacts of climate change into the forecast. It's a lot of work, and forecasting is one of those things that is not completely visible, you know, on a day-to-day basis, but I really want to commend the staff for managing these complex overlapping uncertainties.

One of the key improvements for this year has been really incorporating the known loads information. This becomes especially important given some of these known loads, such as data centers and other manufacturing loads could be very localized, and it becomes really important for us to get that right. And, you know, this also includes charging stations that could be coming as clusters along certain areas. So I just want to thank the CPUC for both sharing insights into methodology of how to

incorporate that, but also helping develop some of those data sets.

So with all that, I'm incredibly thankful, excited about the work we do, and want to just close on a note of thanks to PUC, CAISO, the employees (phonetic) and the many stakeholders without whose collaboration and continued engagement the advancements we make at CEC would not be possible. And also a big shout out to the CPUC staff and CAISO staff who work with CEC very closely under a joint agency working group, which allows for a lot of this work to be managed on a regular manner, and really kind of helps us with the adaptive management of the forecasting products.

So with that, I would like to first invite Commissioner McAllister, and then President Reynolds and Commissioner Baker, who are also with us.

COMMISSIONER MCALLISTER: Thank you very much. Thank you, Vice Chair. You covered the topics really well. Maybe I'll just add a little bit.

So I want to just double down on the message of iteration and the ongoing communication between the agencies. That is really fundamentally the beauty of having this platform and the IEPR, and the first word in IEPR is integrated. And really, the staff does an amazing job of working through issues as they come up, not just

sort of around the big milestones that staff will talk about in terms of the process you're going forward, but also just every day on a daily basis.

New information comes in. As the Vice Chair said, there's a lot of uncertainty, certainly from the federal level, and just evolving marketplaces around AI and data centers. That's a big one these days. There's a fair amount of uncertainty, not just in California, but across the nation. And I'm really excited to kind of get this process moving. I think this workshop is sort of warming up the engine really for accelerating the analysis a little bit down the road as data comes in around the summer, summer loads and the patterns there. And, you know, so far we've been relatively lucky to not have a super-hot summer, but everything can change quickly.

So the distributed resources are of great interest to me and to all of us at both agencies, certainly the fuel substitution, trying to get a handle on that as we move forward, electrification of transportation, all the different distributive energy resources that we actually have healthy levers to pull to help create aggregated solutions on the load side or at the grid edge to help with reliability. And so the forecast actually can shed a lot of light on that as well and give us some ideas of what are the most effective policies that we could use on that

front, which is a way to keep costs down and save ratepayers money over time. And I think that's an area where California is really leading. So I want to always highlight that in this conversation.

I think, I guess I'll wrap up there. I'm really happy to have -- I just -- I'll also reiterate kudos to the Assessment Division staff and IEPR staff. Sandra and her team just always do such a great job. And also the staff at the agencies, the CPUC and CAISO, just the leadership-level coordination and the staff-level coordination are really the lifeblood of this process. And we always kind of have to roll with current events and what happens, and staff just really understands that and does a great job and builds those relationships so that we can have a robust process. Each year, this is a full forecast, and the odd year, obviously, and so lots of work ahead. Really appreciate everyone's participation in this workshop, so thanks for all the attendees as well.

And with that I'll pass it to President Reynolds. Thanks.

MS. REYNOLDS: Great. Good morning, everyone. I'm really excited to be here. Thank you so much to the CEC for including us on the dais. And I want to also make sure I give a huge thanks to the CPUC staff for planning this workshop and preparing for it, getting ready. They

always make it look so easy. And thanks to the participants for being here today. I'm eager to hear the discussion.

I did want to note, Vice Chair, I have some conflicts, so I'm going to be in and out a little bit, but I'll try to listen in as much as possible.

I also wanted to just take a minute to pull some of the threads that were raised by both the Vice Chair and Commissioner McAllister, and note some of the other processes that are ongoing at the PUC that are related to what we're going to be talking about today, and just, you know, kind of note that although we are living in a changing world, and I think that's part of what is driving our need for refinement for the forecast, we're constantly working on improvements and changing our inputs and assumptions to adapt to the changes we're seeing on the system. And so I really did want to emphasize the planning framework that is the bedrock of our electricity system, and note that with the forecast, with the processes that flow from the forecast, we're really not just waiting for things to happen and reacting. We're planning and we're making commitments based on that planning really pretty far out into the future.

And so while there's a lot of uncertainty, and I would say maybe more uncertainty now than we've seen at

least in recent years in the past, we do have systems in place to account for that uncertainty, and our framework for planning is really mature and it's designed to protect ratepayers. And of course the IEPR is a critical piece of that planning. It feeds into so much of the work that we do at the CPUC, including determining how investments can be made at the lowest costs and feeds into our transmission and distribution planning process for those purposes.

And so, you know, just to note in California, we do anticipate significant load growth. All of our regulated utilities are showing growth in load at levels that we haven't seen before, largely driven by data centers and electrification. So there's uncertainty about the scale and the timing of that growth, and it really does make accommodation of those loads challenging.

But I wanted to mention, as I said, a few things that we're doing at the CPUC that are related, and just provide some kind of context to how we're really looking at these problems from many different directions. One is our Rule 30 proceeding, which is getting going, and we did issue a decision for an interim tariff that would allow for expedited and more certain connection to the transmission system. So meant to accommodate large loads and create a process where funding could be provided by the customer up front, and we're going to be thinking about the concept of

repayment when that load materializes. So really a more expedited way to provide certainty and to accommodate new loads coming on, and we'll also help with tracking purposes and help get us more visibility into the future.

Another example of that increased tracking and knowledge is the work that we're doing in our energization proceeding pursuant to Senate Bill 410 and AB 50. We have a new process to kind of segment out the timelines for energization and make sure that we are holding the utilities accountable for those pieces that are in their control and setting then overall timing based on the different processes that -- different steps they need to take to energize new customers, and we've also established a new cost recovery process for PG&E at their request to provide certainty about cost recovery and also lead to efficiencies and cost containment, and as a result, we've seen increases in energization projects that were completed in 2024.

The final thing I wanted to highlight is just all of the work that we're doing on distribution planning and moving towards a scenario planning framework that will allow us to think about and account for different potential futures into a single investment plan for the utilities so that we have more flexibility and we're able to be more nimble in the distribution system planning process.

So with that, I just really wanted to thank you for the opportunity to be here. I'm again looking forward to the discussion and wanted to say thank you again to all of the great work of all of the staffs at the joint agencies including the CAISO, CPUC staff, and of course the CEC staff. Really love to see the coordination of our staffs working together. It just has led to so many great advancements.

So thank you very much, and I'll turn it now to Commissioner Baker.

MR. BAKER: Thank you President Reynolds and thank you to the staff and the commissioners at CEC for inviting me to attend this workshop. I do not want to repeat what everyone else has said except to say I agree with it, and I particularly want to thank the president for laying out, you know, what we're doing to address the challenge ahead. So I'll keep my remarks short and high level.

The Public Utilities Commission relies on the Energy Commission's IEPR process to show us where we're headed so we can determine how much our load-serving entities will need to procure to deliver reliable electric service. Taking a step back from where we are is always helpful at this stage of the energy transition. I personally believe our primary focus should be on promoting

electrification, and to that end my office is interested and very involved with many of the proceedings that the president had highlighted to find new ways to energize new load quickly and efficiently, and I would add with a lot of the things that we're doing particularly the Rule 30 proceeding creatively.

With regards to some of the other new drivers of load, particularly data centers, I believe we need to move deliberately and, you know, we need to meet all new load when it's needed. I also need to -- in this particular area we need to be really careful that we're adhering to traditional cost causation principles and that we're working to avoid cost shifts and particularly stranded assets.

I'm just going to conclude with the, you know, kind of the truism that load growth can put downward pressure on rates and improve affordability if we can bring that load on in an economically efficient manner and avoid unnecessary cross subsidies. In general, I think all of this can help us to create the conditions where Californians can have access to abundant, clean, and low-cost energy.

With that in mind I look forward to today's workshop, and again, thank you for inviting me, and thank you to the staff of the Energy Commission for organizing

this workshop.

VICE CHAIR GUNDA: Thank you. Yeah, thank you Commissioner McAllister, President Reynolds, and Commissioner Baker. Thank you so much for your comments and setting the stage for today.

In the tradition of the CEC's workshops where we have CPUC commissioners, just want to note for record that it's a tie today. We have two and two, and given President Reynolds' confession that she will not be -- that she will have to step out every once in a while, we will take the lead for today's workshop. So with all that, again, a sincere note of thanks to everybody and I will pass now to Heidi.

MS. JAVANBAKHT: Thanks, Vice Chair Gunda. Thank you President Reynolds, Commissioner McAllister, Commissioner Baker for your introductory remarks.

My name is Heidi Javanbakht. I'm the Manager of our Demand Analysis Branch at the Energy Commission in the Energy Assessments Division and I'm going to kick us off this morning with an overview of the scope of updates that we are planning for the 2025 IEPR forecast. I'm co-presenting with Quentin Gee, who is the manager of the Advanced Electrification Analysis Branch and you'll be hearing from him in a bit.

Next slide, please. And one more.

All right. Thanks.

All right. So we decided early on in this forecast cycle that we would limit the types of updates that we're making this year so that we're not implementing any big methodological changes, and this was in response to comments that we've received over the past couple years about how impactful swings in the near-term forecast can be for utilities in procuring resources to meet their resource adequacy requirements. So we are sticking to the routine annual updates which includes incorporating refreshed economic and demographic projections, and adding the 2024 electricity and -- electricity sales and behind-the-meter PV and storage adoption to the historical data set.

And after that we are focusing on developing more scenarios than we've had in previous cycles. This is something that we had had in mind anyway, and then just with all the increased uncertainty with federal policies and all the changes happening, I decided that this would be a good area of focus for this year. So we are rethinking and expanding scenarios for behind-the-meter PV and storage, additional achievable fuel substitution or building electrification, and additional achievable transportation electrification and data centers.

And we are also exploring the incorporation of a new data set from the investor-owned utilities for their

energization requests, also known as the known load data set that was referred to earlier, and that's the data that they are using to inform distribution system planning. That is the largest methodology change that we're making this year, and we are only considering this change for the local reliability scenario so that it does not impact resource adequacy, which uses the planning forecast.

And next slide.

And the reason we are revisiting and expanding our scenarios this year is to better capture uncertainty. And again, with all the changes coming out of the federal administration, uncertainty has greatly increased. So this table on this slide qualitatively summarizes areas that introduce the largest amount of uncertainty for forecasting electricity demand. It's certainly not comprehensive, but does capture the areas with the largest uncertainty. So in this table, we have ranked uncertainty in the short term and the mid and long term as low, mid, and high, and that's based on our judgment of two considerations. The first consideration was the impact that that area would have on electricity demand, and then the second consideration was the extent to which more changes could occur in this area in the future.

And then the last column in this table provides an overview of how we are addressing the uncertainty with

our forecast modeling, and we'll talk through each row here one by one starting with the data centers.

So with the data centers, the potential impact to electricity demand over the next 10 to 15 years is huge, on the order of gigawatts, and this is an area that is changing every time we talk with the utilities. So in last year's forecast, we included approximately 3.5 gigawatts of new data center load statewide, and since we adopted last year's forecast, PG&E has announced nearly 13 gigawatts of data center capacity in the queue. So there's going to be some big changes to our data center forecast this year, just based on that alone.

With data centers, there is a lot of uncertainty around how many projects will be completed, the timeline for their completion, what the market for AI will be in the future, how many data centers will be needed to support that market, among other things. Just because of all the uncertainties in this area, we are developing different scenarios to capture a range of possibility. I know this is a very popular topic these days. It's not actually on our agenda for today. If you'd like more information on data centers, we had a Demand Analysis Working Group on July 16th that focused -- it was several hours of discussion at that DAWG meeting on data centers. So we can drop the link to those materials in the chat, but also feel

free to reach out to us if you have questions or want to discuss further.

The second item in this table is climate change. In the near term there is uncertainty around when we'll see another extreme heat event, and then in the mid and long term there's uncertainty about the frequency and length and magnitude of heat events. Our forecast team has been working with Eagle Rock Analytics and Lumen Energy Strategy to incorporate data from global climate model simulations into our forecast to assess climate change impacts on electricity demand and to improve our methodologies around that.

The next area of uncertainty is with the hourly and peak loads. These are highly influenced by weather and extreme heat events. Our forecast products now include a probabilistic hourly data set that takes inputs from the downscaled global climate model simulations that we've been working with Lumen Energy Strategies on. The one-in-X year peak values are an output of the probabilistic hourly data set, and that allows us to look at what we call normal which is a one-in-two-year peak as well as a one-in-five-year and one-in-ten-year values, and so this gives us a range and likelihood for the annual peak demand.

Tariffs are of course another area of uncertainty, and we'll be talking about these more today in

our upcoming workshops. Many of these are still being negotiated, so in the short term there is high uncertainty in this area. And because these are not finalized, they are not captured in the economic projections that we're using for this year's forecast. There's uncertainty around how much the new tariffs will impact prices for technologies which just as an example would impact adoption rates of PV and storage. We expect PV and storage prices to increase which along with the elimination of the federal tax credit at the end of this year will increase the payback period and most likely decrease adoption rates.

The federal tax credits for behind-the-meter PV and storage as I just mentioned expire at the end of the year. That is a change that we know is happening at least, and will be in place at least for the remainder of this federal administration. But what remains uncertain is how the market will react to both this and the tariffs.

And so the way that we're going to handle this in the forecast this year is, again, to produce more scenarios around PV and storage adoption. And this is where I'm going to turn it over to Quentin to cover the remaining items on this slide from the transportation and building electrification perspective.

MR. GEE: Great. Thanks, Heidi.

Yeah. As Heidi mentioned my name is Quentin Gee.

I'm the manager of the Advanced Electrification Analysis Branch. We focus on transportation building efficiency and fuel substitution for building electrification technologies. So yeah. As Heidi discussed, some of the uncertainties above, I'll talk about some of the main ones here towards the bottom. Tariffs do -- are going to play a role because of the -- just the uncertainty when it comes to imports. A lot of vehicles for transportation are made in the United States, but there are imports, so those will have -- introduce uncertainty about exactly how to model overall demand for vehicles.

When looking at tax credits, as Heidi mentioned, yeah, there certainly are tax credits on self-generation technologies. As well we're looking at tax credits for large -- excuse me, light-duty vehicles and basically electric vehicles but zero-emission vehicles, and also medium- and heavy-duty electric vehicles as well. That's another tax credit that's been lost.

Home efficiency upgrades have been -- will -- the tax credits for those end at the end of this year. The same would go for heat pump tax credits. So a lot of just incentives for adopting electrification and clean technologies have been eliminated at the federal level. There are some ways, and looking at the future the Governor Newsom in California signed an executive order, and now the

Air Resources Board is going to be pursuing or looking at new ideas to encourage electric vehicle adoption. So on the one hand, you're losing incentives at the federal level, but we are continuing as a state to think creatively about ways to increase zero-emission vehicle adoption in the state.

There are CARB -- so California Air Resources Board and local air district regulations. A lot of these, there's some uncertainty here with regards to zero-emission appliances and the standards that underlie those. There have been some wins for some local air districts when it comes to some of the zero-emission appliance regulations, but there also have been some sort of instances in which standards have not been adopted and -- or standard implementation has been delayed. So there's some uncertainty there which will feed into the longer term.

Finally when it comes to hydrogen, there's still I think a little bit too much uncertainty in this area. We are proceeding in the IEPR in the Senate Bill 1075 part of the integrated -- this year's integrated energy policy report to think through the possibilities of hydrogen and the role in which it could play in the economy of the future, but as far as the forecast component goes, at this point we don't have enough confidence for integrating it into a forecast. In the short term, we're not anticipating

any clear impact, but it's primarily in the long term where the impacts
are -- or the uncertainties just are a little bit too much for us at this point to introduce into the forecast.

We are continuing to -- you know, as I mentioned, the Senate Bill 1075 work exploring hydrogen pathways and then also when it comes to the ARCHES Program that the Governor's Office of Business and Development has pursued pretty rigorously their funding source -- or their funding and their program project opportunities in there. And we're continuing just to stay close to the ground on those. And we will -- as we get more confidence in that, we are going to be looking closely at hydrogen. But for this year we are not going to include electricity demand for hydrogen in that.

And I think that's it for characterizing uncertainties. There's a lot here we're always happy to engage with stakeholders that want to contact us and discuss further, but we hope that this kind of gives you the broad strokes on, like, you know this age of uncertainty.

MS. JAVANBAKHT: Thanks, Quentin.

We can move to the next slide.

So again, the primary way that we are capturing uncertainty in the forecast is by assessing multiple

scenarios that look at a range of possible outcomes. We are in the process of designing a set of scenarios for the forecast components that are driven by policy decisions, and we'll be presenting those proposed scenario designs at our August 18th Demand Analysis Working Group meeting and the August 26th IEPR workshop.

In the meantime, if you have any ideas for scenarios please reach out to our forecasting team to discuss. It is really important that we are covering the range of possibilities so that if things change prior to the 2026 IEPR forecast being developed, we are able to quickly pivot. Though it's not ideal, if there are things that change early next year after forecast adoption it is possible for us to reconfigure our planning forecast or a local reliability scenario. Those two main products are made up of different combinations of the load modifiers so it is possible for us to swap out one scenario for another as long as those are already developed and adopted as part of the suite of forecast products.

And on that note, our current thinking is that we're going to wait until October to decide with stakeholder input which combination of scenarios go into the planning forecast and the local reliability scenarios. That way we can look at the load modifier results, the draft results, and have the latest news on the federal

policy changes to inform our decisions around which combinations make the most sense for resource adequacy, integrated resource planning, and transmission system planning.

And next slide.

So just wanted to wrap up with our timeline for public input this year. For anyone new to this process, our DAWG meetings, the Demand Analysis Working Group, meetings take a deeper dive into the forecast methodology, and are a less formal forum meant for open discussion and feedback from stakeholders while the IEPR workshops like today are more formal, and we typically don't have as much time to dive into the details. Our next DAWG meeting is August 18th, where we'll be covering the inputs and assumptions for behind the meter PV and storage, additional achievable energy efficiency, fuel substitution, and transportation electrification, and that will include the proposed scenario designs and more discussion around the policy uncertainties.

The same topics will be covered more formally at the IEPR workshop on August 26th, and then after that we'll spend September and October running all of our forecast models. We'll come back at the end of October to present the draft load modifier results at a DAWG meeting and then the draft overall forecast results will be presented. The

load modifiers will be presented on an IEPR workshop in November and then the overall forecast results will be presented at a IEPR workshop in early December.

We are accepting comments all along the way, but after that December IEPR workshop we have one last formal comment period and then we'll be finalizing everything over the holidays for adoption at the CEC business meeting in mid-January of 2026.

And that's it for my presentation. I'll take any questions.

MS. JAVANBAKHT: Now I'll turn to the dais, Vice Chair Gunda or any other members of the dais if there are questions for Heidi or Quentin.

VICE CHAIR GUNDA: No. I just wanted to say thanks to Heidi and Quentin. I've been tracking what's been said, so thank you so much Heidi and Quentin. So thank you. I don't have any questions.

Commissioner McAllister?

COMMISSIONER MCALLISTER: No. Just great to have a handle on the process, and I appreciate the overview and I think we're identifying the right kind of topics to do scenarios around so I appreciate that. I've been paying some attention to all of this.

VICE CHAIR GUNDA: Great. I think I want to just maybe highlight what Heidi mentioned in terms of the Demand

Analysis Working Group being an informal process for engagement.

Heidi, that's open for anybody that's noticed and it's open for anybody to join?

MS. JAVANBAKHT: Yes. Yeah. That's correct.

VICE CHAIR GUNDA: And are those meetings hybrid, Heidi?

CHAIR HACKER: They are hybrid. Yeah.

VICE CHAIR GUNDA: I think it'll be good to -- I know you were going to put that in the --

MS. JAVANBAKHT: I will.

VICE CHAIR GUNDA: -- chat. I think it'll be good to just elevate -- continue to elevate for anybody who's interested in participating in those. I don't see any other dais members having questions, so I'll pass it back to you, Sandra.

MS. NAKAGAWA: We're going to go to the audience Q&A. Looks like we have a couple, and Heidi's going to lead us through the audience Q&A portion.

MS. JAVANBAKHT: Yeah. So our first question is from Claire Broome.

You mentioned scenarios with behind the meter resource adoption. Will the CEC be adding ability to analyze scenarios with greater adoption of front-of-the-meter resources on the distribution grid?

This is something that we are still discussing internally. This has a lot of implications to CAISO and CPUC processes, so at this time we're not planning on incorporating front-of-the-meter resources into the forecast, but it is something that we are still discussing internally.

And Vice Chair Gunda, I don't know if there's anything you wanted to add there.

VICE CHAIR GUNDA: No. Thanks Heidi.

I think it's just two points. I think it's really important to continue to evaluate the opportunity, the impact of that on the demand side, and I think I just want to appreciate, Heidi, you and your team for continuing the conversation and thinking through how to incorporate that when it's possible, and I just want to maybe clarify what you just said. We're not doing that for this cycle, but you're continuing to think through that.

Thank you.

MS. JAVANBAKHT: The second question is from Ian McMillan (phonetic), and this one, Quentin, is for you.

Can you touch on how you are projecting energy needs at the LA and Long Beach ports?

MR. GEE: Yeah, thanks for your question, Ian. That's a good one. Generally speaking, part of the electricity demand associated with the ports of LA and Long

Beach would be attributed to sort of general economic growth that would presumably be captured in our industrial model. When it comes to -- I think probably one of the main questions you're thinking about is more around electrification of components at the facility such as, you know, yard tractors, side handlers, those sorts of equipment that's at the port of LA and Long Beach.

We do have an off-road electrification model that is incorporated into the transportation energy demand forecast. It is not in our traditional -- what we call a load modifier, the kind of light-duty vehicle and medium- and heavy-duty trucks or vehicles that we normally have in there, but they are incorporated into our off-road model, which does go into the sort of the baseline forecast. And we are anticipating electrification of port and cargo handling equipment at the ports associated with that.

MS. JAVANBAKHT: Thanks, Quentin.

The next question is from Daniel Nelly (phonetic).

Could you repeat why tariff impacts won't be making it into the 2025 IEPR?

Yeah, Daniel, we'll be talking about this more today. Basically, the tariffs are not final, and we use economic and demographic projections from May from Moody's, and they were even less final back in May. So, that's the

primary reason.

And then with the PV and storage costs, our team has talked with NREL. We use projections from NREL for the price forecast for PV and storage, and they're in the process of updating those projections to incorporate the tariffs, but those won't be available until the fall, which is too late for us to incorporate in this year's forecast.

MR. GEE: Yeah. And when it comes to transportation, I would also add on that front, vehicles, it's tricky to sort of fully model out vehicle prices with tariffs given the uncertainty that there is going on right now. We are going to pay close attention to that, and as necessary we will be able to update our expected vehicle prices across different segments, different vehicle types. So, like, you know, you might imagine like a SUV or a pickup truck -- well, pickup trucks most likely not, but sedans or other types of vehicles and sort of model that out.

But right now, given the uncertainty about, you know, just when, how much, you know, the tariffs are going to be, it would take a lot more work at this point, and we need more certainty until we can begin that.

MS. JAVANBAKHT: Thanks, Quentin.

I'll go ahead. Next question comes from Roger Lin.

Do the IOUs consider uncertainties contemplated for analysis in this demand forecast cycle when adding data centers to the queue? For example, just referencing the 13 gigawatts that PG&E has in the queue.

They do. PG&E and SCE and some of the other utilities had presentations that talked about how their forecasting data centers that they presented at our July 16th DAWG meeting -- all the slides are posted, so I recommend taking a look at those. But they do look at the application status and how far along the projects are and, like, how much commitment that they've shown when they're considering how to forecast and plan for those.

BOARD MEMBER SCHENK: Heidi, can I just request you also just comment on the spirit of that question how the system-level forecast is being kind of harmonized at a busbar spot level to the bottom-up forecast where some of the distribution planning is happening?

MS. JAVANBAKHT: Yeah. Well, this is an ongoing process with some challenges, but we started this process with data centers.

So last year we worked closely with five different utilities that are seeing a lot of data center load growth so that we could incorporate that into the forecast, and they sent us information that came from the applications that they have in the queue for data centers.

So it's bottom-up, it's site-specific information.

We made some adjustments to that based on some historical trends with data centers and how they use energy based on or compared to the requested -- the capacity that they request. So that's how we incorporated it into the forecast at the system level, and then we also worked with the utilities on the locations of all of these projects at the busbar level.

We do work with CAISO. So after our forecast is adopted each January, we have another product that we develop after that that goes to CAISO where certain components of the forecast we disaggregate down to the busbar level, and that goes to CAISO for transmission system planning. So we did that process with the data centers this year and have -- even as late as earlier this week, have been working with some utilities to make adjustments to that just based on their latest and greatest information. So we are -- it is an evolving process and we're learning a lot as we go through this, but we are trying to make sure that these large loads are accounted for in our forecast so that they can be properly planned for at the transmission and distribution levels.

Quentin, I don't know if you had anything you wanted to add to that. If not, that's fine. Okay.

And then we also have another presentation later

this morning from Asish Gautam on how we are incorporating the known load data from the utilities into our forecast this year, and the known load data set is what the utilities are using for distribution planning.

Okay. There are quite a few questions. I'm not sure that we're going to have time to get to all of them. I am going to prioritize the ones that have been upvoted.

So the next question comes from Matt Vespa (phonetic).

To what extent is managed charging assumed for medium- and heavy-duty vehicles to lower coincident peak demand for those charging stations?

And I saw there is a similar question about load shifting and how the CEC will incorporate its goal of 7,000 megawatts through load shifting in the demand forecasts.

Maybe, Quentin, you can take both of those.

MR. GEE: Okay. Yeah. Great. Tanya and Matt, thank you for your questions. They're kind of interrelated in a way.

But sort of to get to the NBHD question, we do have a load model -- an electric vehicle infrastructure load model that we employ. Basically it is -- we have base load shapes of presumed charging demand from medium- and heavy-duty vehicles by different classes. So, class A trucks, big old heavy trucks that you see on the road, they

have a different charging cycle than we would expect from a class four box truck or something like that.

So we have those baseline load shapes and we integrate them in with time of use rates that vary by utility, and we have a responsivity sort of multiplier that we use to reduce load -- the presumed load at peak in the sense that -- or given the understanding that people are inclined to avoid charges. That doesn't mean that medium- and heavy-duty charging goes to zero during peak hours, but it is reduced. We are going -- so that's the way the current load model works. We're looking at other ways of thinking through a good way to do load analysis with those. But that's how it's currently done in the IEPR. That's done for light-duty and for medium- and heavy-duty vehicles. And we do see a reduction in the peak contribution for medium- and heavy-duty vehicles on that.

When it comes to the 7,000 megawatts goal of demand flexibility, that is another situation. There's a little bit of interface there with medium and heavy duty charging because medium heavy duty charging may be an opportunity for some demand flex. But there's a whole lot of additional demand flex potential out there for light-duty vehicles, ag water pumping, you know, like, air conditioning, HVAC systems, water heating systems, lots of different opportunities for load flex that we explored in

the Senate Bill 846 report, and we are going to be doing an update on that this year.

As far as integrate -- so we have done some additional work on that through the Senate Bill 100 process as well, and we have integrated in a demand flexibility tool that can take in all of these different types of loads and assign a certain degree of potential opportunity for demand flexibility at each given hour of the year with constraints on how often demand flexibility can be called upon. That is integrated into a cost model that kind of evaluates -- a supply model that evaluates how there would be responsiveness as a result.

Right now it's much more into sort of, like, we're evaluating potentials. We're not actually at the point yet where we can treat that as a full load modifier that goes into the forecast, so we are working our way towards thinking through that. That is sort of on our agenda.

Some of the certainties that need to be sort of -- that need to unfold on that front are clear programmatic design and implementation, a better sense of costs, and actual kind of, like, you know real world results that can allow us to build that in with more certainty, but there is a lot of potential there, and I look forward to reading through the section on Senate Bill

846. But right now can't integrate that into the forecast, but we are hoping to be able to do that in the future.

COMMISSIONER MCALLISTER: I wanted to just jump in real quick on that as well. Thanks. Really appreciate the answer, and you both -- for both Heidi and you for fielding these questions. And just keeping an eye on time. I think we're going to have to move on here.

But I did want to just highlight that there is a lot of testing and experimentation going on at increasing scale on load flex and sort of pragmatic ways of harnessing and aggregating it. And last week PG&E did sort of a test but at some scale with some partners to mobilize battery -- behind-the-meter batteries as a load flex resource. And they got many hundreds of megawatts in predictable, dispatchable, aggregated behind-the-meter battery resource that portends really well for really mobilizing and putting into operation the tools that we need to meet the load flex goals.

So I just wanted to highlight that. It's not sort of directly related to forecast at this moment, but certainly there's a lot of progress there.

MR. GEE: Great. Thank you, Commissioner. That is a technology and an opportunity that is also in the demand flexibility tool, that and also vehicle to grid. So yeah. As we see more results like this, we'll be able to

integrate them into the tool and also think about building it in as a load modifier in the future.

VICE CHAIR GUNDA: Yeah. Quentin, I just want to kind of uplift and thank the work that the team is doing on, you know, the IMD data that we have, you know, the metadata, trying to assess the coincidental load of different, you know, different loads coming online. So I just appreciate that ongoing work and continuing to think about, you know, optimizing the investments necessary on this distribution grid for maximizing consumer benefit, both in terms of having the capacity to interconnect, but also, you know, not overbuilding and maximizing the use of the distribution grid.

So really appreciate that work that the team is leading, so thank you.

MS. JAVANBAKHT: Okay. So we've got three more questions, which I think -- I think we have time to get through all of these, and I'm going to take the data center question first.

Regarding data centers, some bring supply with them. How does the IEPR consider data centers with on-site generation?

So the way that our forecast works, the distributed generation component of the forecast is separate from, like, the data center component or the other

sectors in that we forecast demand and then we forecast generation in two separate models.

With data centers, we are monitoring this. We know that there are data centers inquiring about having on-site generation that would potentially fuel their electricity needs 100 percent, and they wouldn't be reliant on the grid. I think it depends on what sort of setup they have, but we are talking with different utilities about this and keeping an eye on it so that we make sure that we're incorporating it into our forecast in a way that makes sense.

And while we're on this topic, I will also just note that we did talk with SoCalGas yesterday. They have a proposed tariff that CPUC is currently reviewing for microgrid optional tariff that if that moves forward could bring some potential options -- create more potential options for on-site generation for large customers.

And then, okay. I'll take the next question from Lee Ewing (phonetic).

What is the methodology for attributing new forecasted load to individual LSEs?

I assume that this question has to do with data centers and how we attributed those data centers to LSEs in last year's forecast. I will start by saying we are improving how we do this process for this year. How we did

it last year was we collaborated with the IOUs, PG&E, and SCE, and asked them how many of those data centers and which data centers they expected to have service from them versus service from a CCA or other LSE in their territory.

And so that's -- we had used their input last year to do that allocation. This year, we plan to have a lot more discussions and collaboration with the affected LSEs, and we'll make sure to -- this was all happening pretty late in the process. For last year, we should have more time to build in more collaboration with the LSEs in this regard for this year.

Okay. And then the last question: is it possible that certain behind-the-meter solar deployment scenarios might see an increase in near-term deployment to capture expiring tax credits? That's part one of the question.

And then, part two -- or actually maybe a separate question -- can you share how multiple scenarios and sensitivities flow through into CPUC and CAISO inputs, and is there a base case that gets used?

So to answer the first question about the behind-the-meter solar deployment first. We have a lot of interagency collaboration, as was mentioned at the beginning of this workshop, and one of the areas that we work really closely with CPUC on is with tracking solar and storage adoption. So even though the main historical

dataset that we use goes through the end of 2024, we are tracking 2025 installations from CPUC's data. And so, we should be able to capture some of those trends in our forecast.

We are -- as this is alluding to, wouldn't be surprised if there is an increase in adoption through the end of 2025 with people trying to get those credits before they expire, but that's something that's difficult to forecast and would really only impact 2025, and maybe a little bit into 2026.

Okay. And then, the second part: can we share how multiple scenarios and sensitivities flow through into the CPUC and CAISO inputs, and is there a base case that gets used?

There is a base case that gets used. We call that our planning forecast, and then the planning forecast is used for resource adequacy and integrated resource planning. And then we have a local reliability scenario that's used for exactly what sounds like: more localized planning and studies for the transmission system and distribution system. Those are all outlined in our IEPR report. So you can find the details in there under -- there's a section called the single forecast set agreement, and so we have an agreement with CAISO and CPUC on which scenarios -- which combination of scenarios will get used

for different planning processes.

Okay. We had one more question come in. We'll take this one, and then we should move on.

And Quentin, I think this one's for you.

MR. GEE: Yeah.

MS. JAVANBAKHT: Does the IEPR modeling include the updated scoping plan and SB100 goals? And then what about the impacts of federal policy changes?

MR. GEE: Okay. Thanks, Rosa (phonetic). The scoping plan, so the IEPR modeling does include some of the policies that have been implemented that have been, you know, expressed or put forward in the 2022 scoping plan. So things like Advanced Clean Cars II, we have that in Advanced Clean Fleets. We have that as a possibility in there, but as you may have heard that the Advanced Clean Fleets rule has been removed from federal approval at this point.

So there are things that are -- you know, there's uncertainties there, but we have that framework to include components of the scoping plan. But where the scoping plan does not have an explicit policy pathway forward to reach certain goals, then we do not include those scoping plan goals. For instance, vehicle miles traveled reduction is a goal in the scoping plan, but it is not backed by an explicit policy.

SB100 is a little bit different. SB100, that's a supply issue and the demand forecast or actually the demand scenarios, which is a sort of an extension of this forecast that we do, that does go into the demand component of the Senate 100 Bill report that needs to be, that is in development. And that sort of -- that is sort of is used to inform what the supply would need to be -- what the supply mix would need to be to meet the demand. So there is a lot of -- there's the IEPR sort of informs SB100 in a way, but not obviously not completely.

Federal policy changes, I think I may have touched on this earlier, but yeah. Depending on the policy changes, it's hard. That's why we're kind of doing the different scenarios at this point in time, but there have been a lot of federal policy changes at this point. So we're kind of hoping for that broad swath of scenarios, we'll be discussing further because they do introduce a lot of uncertainty.

VICE CHAIR GUNDA: Heidi and Quentin, I know we are going to move off from the questions here. I just wanted to say, first, you know, thank you for all the incredible work that's happening on understanding the uncertainty. And as we discussed, I think continuing to daylight the analytical work when the time is right on understanding how these uncertainties -- you know, the

magnitude of a certain uncertainty could flow downstream into different parts of our planning processes, whether it's RA, whether it's transmission planning, distribution planning, and really the impact of doing that both on the positive side of being ready for load growth and on the negative side of potential higher rates, right? So like, how do we think about that balance?

And I know that there's a lot of work that has been started, and I just want to recognize for the public as a whole that's being currently done and would love and welcome the CEC team with our colleagues at the other agencies to put them in these public workshops when we are ready.

Thank you.

MS. JAVANBAKHT: Yeah. Thanks, Vice Chair Gunda.

Okay. In the interest of time, we're going to move to the next presenter. Thank you for all the questions, and there is one question left in the Q&A from Rajiv Dabir (phonetic). We will type a response to that one but wanted to move to the next presentation.

So, with that, we've got Mathew Cooper up next to talk about the economic and demographic updates.

MR. COOPER: Good morning. I'm Mathew. I help to coordinate the various parts of our IEPR forecast, and I'm going to go over our updated demographic and economic

projections for 2025.

I want to give credit to Nancy Tran from our data integration branch. This is the result of her hard work and expertise.

So next slide.

Economic and demographic data are some of the primary inputs to our energy demand models. They're key drivers of electricity and gas consumption, which makes sense because energy is consumed by people and businesses, so it's obviously linked to demographics and to economic activity. For these drivers, we rely on historical data and forecasts created by other state agencies and other external entities. We use regression to establish relationships between historical energy demand and historical economic and demographic variables, and then we use the forecasts for those variables to extend that relationship into the future.

For electricity, we forecast for eight different planning areas, which are further divided into a total of 20 different geographic zones. For gas, we forecast the service territories for the three main gas utilities: PG&E, SCG, and SDG&E, plus an "OTHER" category.

So we track these economic and demographic variables not just at the statewide level but at the forecast zone level. The charts that I'm going to show are

statewide, but our models are actually run at the more granular levels.

The most important demographic variables we look at are population and households. For economics, we track a lot of different metrics of economic trends. Not all of them are used in every forecast. The modelers for different economic sectors, such as commercial or industrial, select the variables that are the best predictors of energy demand, but even when they're not used directly these quantities provide important context and insight into trends.

The next slide is a little more background information.

In the past, low, mid, and high inputs were used to create low, mid, and high energy forecasts. We haven't done this the last few cycles because the impacts of policy and technology changes have a greater magnitude than the impacts of economic and demographic changes, and those potential policy and technology changes are captured in our additional achievable load modifiers used in the planning and local reliability scenarios that Heidi was just describing. We do review low and high economic cases, but at least for now we're still planning to use a single mid set of inputs for the forecast.

We have data on many variables. This

presentation is just going to go over a few key ones, which are shown on this slide, and the demographic data comes from California's Department of Finance and the economic data comes from Moody's Analytics.

The California Department of Finance, or DOF, was created to serve as the official demographic source for state planning and budgeting. It's used by a variety of entities. They conduct annual fine-tuning surveys to accurately estimate population and households, and these baseline estimates are anchored to the most recent census data. So we use DOF because for the State of California, it's ultimately more accurate given the extra effort they go through.

Moody's population data also uses the latest census information, but they use a top-down methodology, so the assumptions that go into creating their growth rates derive from their national forecasts, and they also don't have as many buckets of population type. So we don't directly use their demographic data except for comparison purposes, which in general Moody's population is usually a little more pessimistic, but the trends are similar because the trends are nationwide, which are right now primarily low birth rates and the impacts of immigration policy.

Moody's Analytics has a full suite of economic data, so we use them for all of our economic variables,

just keeping in mind that, again, Moody's forecast methodology is top-down, so the state and county-level data is driven by the national forecast.

Next slide. Next slide, please. Thanks.

Before we look at the actual numbers, I'll go over some key changes we've observed so far. To start with, we should acknowledge what's probably at the forefront of everyone's mind, which we've already discussed a bit: the impacts of tariffs and immigration policy and other actions from the new federal government this year.

According to our economists, forecasting economic and demographic trends during the current administration is notably complex due to elevated economic uncertainty, stemming from rapid policy shifts, trade disruptions, and regulatory volatility. The high level of uncertainty of fiscal and immigration policy measures introduces substantial variability into standard modeling assumptions. This impedes accurate long-term projections of things like labor market dynamics, household formation rates, and regional economic growth.

So high uncertainty and rapid changes obviously make forecasting quite difficult. Rather than chasing large swings back and forth in tariffs and other policies, both DOF and Moody's seem to have been cautious in their predictions, so as a result, the current demographic and

economic numbers are not wildly different than last year, although there are significant impacts, of course.

And as Heidi mentioned earlier, this data is from May, so the direct impacts of tariffs are not yet fully present in the data, and there's still significant ongoing changes to policies anyways, so the tariffs can't be directly represented in the 2025 IEPR forecast.

But that's not to say that these policy changes aren't showing up at all though in this data. In the economic variables, we do see somewhat of a slowdown in the near term, followed by a rebound a few years later, and then a return to long-term trends, which are consistent with previous forecasts. So this is what we're planning to use for the 2025 IEPR forecast input, just keeping in mind there's still a high amount of uncertainty present, especially in the near future. The economic slowdown may be worse than what these predictions show, especially given recent reports about inflation and unemployment.

Just going back to the slide here, demographic variables also have some uncertainty. Population is lower, although still similar to previous projections. The number of households are higher than previous forecasts because of an ongoing trend towards smaller households.

Some key economic assumptions for Moody's May forecast are slower growth in the near term, 2025 and 2026,

with a hopeful rebound in 27-28. They assume that extremely high tariffs, including those on China, will prove to be brief, but tariffs overall do remain higher than last year through the end of this presidential term. They assume that some kind of global trade war is expected, which will negatively affect the U.S. economy. For example, homebuilders are feeling the challenge of tariffs with rising material costs, and deportations also shrink construction labor. An increased uncertainty on the labor market is basically impacting all employment sectors. So we haven't run our models with this data yet, but the likely impacts on the forecasts are that more households will increase energy consumption in the residential sector, and economic slowdown will reduce energy demand in the short-term across all sectors.

Next slide. One more, please. Thanks.

So let's get into demographics first. The new population forecast is the blue line, the red dashed line is last year, and the green smaller dashed line is the year before that. So you can see that 2024's data in the red line showed a return to positive growth compared to 2023. This year is lower but still positive, and shows basically sustainable population growth over the forecast period. The reduction is most pronounced in the most populous areas of the state, San Francisco and Los Angeles. The main

drivers for this are lower fertility rates and changes in immigration demographics, specifically a shift from ages in which immigrants were almost certain to have children to older immigrants where the likelihood is smaller. I didn't include a chart showing population by age in this presentation, but we do track that and the cohort of ages 5 to 17 is lower than previously forecast. And these slides also have an appendix which shows population for each of the planning areas separately, so in case anyone wants to review their area.

Historically there's a gap between SCE and PG&E, with SCE having a higher population but the gap narrowing over time. So the total population for PG&E planning area starts approaching SCE towards the end of the forecast horizon. This narrowing of the gap between Northern and Southern California is due to relatively more favorable assumptions for fertility, life expectancy, and births in Northern California, and this trend has been consistent over the past few IEPRs and continues this year, although it's slightly less pronounced.

Next slide.

Last year in 2024, there was a revision to historical households, resulting in a higher starting point compared to the 2023 data. This year there was also an update incorporating better intercensal data, which

improved the historical accuracy but didn't change the starting point of the forecast. The gray historical line there is from the revised 2025 data.

This year we see a steeper rise in number of households, especially in the near term. The reason this is growing faster even though population is growing slower is that people are living in smaller households. This trend was already present in past years, but the latest data shows it increasing. And this is due to housing development patterns such as rises in single-person households, couples without kids, single-parent households, increased number of multifamily units with more people living in smaller units. These all lead to an increase in households without a corresponding increase in population. And lower birth rates mean people are delaying marriage and childbearing, causing them to live alone longer, so there's a decreased doubling up of adults living with parents.

For example, if a family consisting of five members, two parents, and three children, as the children reach adulthood, they would establish their own households but don't immediately have children, so that results in a total of four households instead of one, but without increasing the total population.

And this goes along with a shift towards smaller housing units, more condos, apartments, and ADUs, and those

are usually for singles, single parents, or childless adults. Again, boosting household growth but not population.

And lastly, an aging population is also a factor. People are living longer and living independently for longer or aging in place.

Next slide, please.

This is just to show the same point a little more clearly, that households are getting smaller. This is just the data from the last two charts put together, population divided by households. So population is slightly lower, but households in the denominator is larger. So overall, the quantity is decreasing.

The one other factor to mention is a marginal decline in rental costs that persists in some areas of the state, which allows for an increase in household formation. This trend does not extend to major metropolitan regions, such as coastal Southern California, where rental costs are still elevated. In fact, the housing inventory declined there following the wildfires, resulting in sustained high property prices and limited supply, and that kind of market condition would typically incentivize construction activity, but there's still several uncertainties there, like construction costs are volatile and labor shortages are -- are happening. So that's a good segue into

economics.

So next slide. And one more.

Personal income. So this is the same color scheme, and all these series are in 2024 dollars. The 2025 data has a higher starting point than 2024, but there's a dip in the growth rate in the next few years. So the series is kind of more wavy, but recovers to end on a similar long-term growth rate as the previous vintages and lands kind of right in between them in magnitude. It is hard to know how big that initial dip will end up being. Labor shortages, budget uncertainties, tariffs, and AI technology continue to make employment volatility remain above average.

Note that AI innovation, it might be associated with some specific new jobs, but overall likely means less total jobs in the tech sector and thus less income, and I think we're seeing that already. Rapid advancements in AI are driving widespread layoffs, specifically in Silicon Valley and the Bay Area. And it's disruptions to high-wage employment, engineering, analytics roles, which impacts consumer spending and even could pose long-term challenges to the stability of the region because it's tied to tax revenue, et cetera.

Next slide, please.

So for gross state product, these lines might be

a little harder to see, but it's a similar shape as the previous slide. We had a higher starting point due to historical data revisions, but slower growth in the near future. And then a return to long-term growth that's similar to our previous vintages. And just note that most of our modeling, we usually use the growth rates for these variables as inputs. So the exact starting point doesn't matter as much.

And again, of course, I just wanted to mention the high uncertainty associated with federal policy. Right now, the uncertainty itself and perhaps some preliminary effects of tariffs appear to be slowing the gross state product, but it's possible that tariffs and other policies will have a bigger effect than this, causing a bigger slowdown. Recent reports on inflation and employment might indicate that.

Next slide.

Manufacturing output. This has been indexed to an arbitrary value of 100 in 2024, just to compare with the previous vintages. You can see that manufacturing output is lower in the near term than the last two forecasts, and to some extent, this reflects changes in immigration and trade policy and broader uncertainty. But we should also mention that the 2024 historical data was weaker than initially expected, so it was revised downward also.

Volatility in manufacturing is due to global trade uncertainty, shifting international agreements, tariffs, trade wars lead to disrupted supply chains and volatility in import-export flows. California is home to nation's largest ports, as touched on earlier, and they face disproportionate impacts. Fluctuations in cargo volumes at Los Angeles, Long Beach, and Oakland would affect employment, logistics infrastructure, and broader regional economic stability, which in turn would negatively impact our economy.

But we do see a recovery and a return to growth in the forecast. Manufacturing will still play an important role in our economy, supporting high-wage jobs and small businesses and part of, you know, a global supply chain.

Next slide.

So commercial employment. This is a key input for our commercial sector, and we define commercial employment as total non-ag employment minus construction, manufacturing, and natural resources. So some of the areas like agriculture and construction that are being impacted most by immigration policy are not reflected in this specific chart, but they will be inputs into our energy forecasts for those sectors, for ag and construction. Even without those, you still see an obvious slowdown here over

the next few years. And flatter growth is also due to the Bureau of Labor Statistics' revisions a few months ago, lowering historical estimates, where 2024 ended up being weaker than anticipated. Last year, high interest rates and inflation were weighing on producer sentiment.

And the BLS revisions from last week would show an even weaker job growth for 2025, although that's not in this chart. And that's probably due to cuts made by the Department of Government Efficiency that might be showing up in the more recent data, and just in general, layoffs in big companies, which has a domino effect to other areas.

And impacts from the federal administration. Economic uncertainty in general just appears to be slowing employment. So since we're using the May vintage, that most recent updated jobs report is not in our forecast, but some of the drivers for that downward revision, such as tech sector layoffs, are kind of a continuation of existing trends that Moody's was already tracking and accounting for. Main drivers for employment continue to be technology and innovation type jobs; manufacturing, like aerospace, defense; and healthcare. Notably the healthcare sector experienced significant growth last year, with projections indicating potential continued expansion through the rest of this year, which is contingent on the absence of policy interventions like budget cuts.

Conversely, sectors such as transportation and warehousing have the most uncertainty due to impacts from immigration enforcement actions, tariffs, and federal policy modifications resulting from budgetary reductions. Similar uncertainty in the education sector, which faces some funding threats. So, yeah, still lots of open questions, but this is the data that we'll be using for the forecast this year.

So next slide.

I think that's it.

So we'll go to questions from the dais first.

VICE CHAIR GUNDA: Matt, I don't have questions. I mean, I'm tracking much of the information.

Maybe just one quick clarification on how locked the assumptions are at the moment, especially on the employment side that you just mentioned. Are we planning to make any further adjustments before the final forecast is run, or -- and if you're just going to talk to that, that would be helpful.

MR. COOPER: Yeah. We're not planning to. This is a question, obviously, that we talked about this last year, I think, also, that, you know, we kind of have to have a cutoff point for our data. The Bureau of Labor Statistics data goes to Moody's. Moody's goes to us. Our data branch does a lot of work to, you know, organize and

clean the data and assign it to forecast zones. And so we kind of -- for our forecasting process, we do have to have a cutoff somewhere.

And I would say there was a downward revision, but it was part of sort of an existing, sort of ongoing trends, like I mentioned, the tech sector decreasing. And so I don't know that -- we haven't run the data in our model, so I couldn't specify exactly what the impact would be, but I think that the trends are not particularly changed.

Yeah. Does that answer it?

VICE CHAIR GUNDA: Oh yeah. Absolutely. Thank you, Matt. I will pass to other commissioners and reserve some time for the Q&A, from public Q&A.

So I'll pass to Commissioner McAllister. And I saw Commissioner Matt Baker come --

COMMISSIONER MCALLISTER: Yeah. Commissioner Baker was on first.

Commissioner Baker, if you want to go first, that's fine. Or not, no.

So I just -- sorry. A quick question about, I guess I'm wondering, you know, you totally get -- you know, you have to have a cutoff. And I think that's, you know, understandable and, you know, an annual kind of, okay, we got pencils down on some of this stuff, so we can actually

do the analysis.

I guess I'm wondering, with all the federal uncertainty, and particularly around immigration, which, you know -- I guess I'm wondering sort of if that's at the margins of your analysis, and maybe not, you know, relevant for this work. But it certainly seems like, you know, tight labor market, sort of the uncertainty around -- you know, it's maybe a small relative population, but maybe has outsized impacts on actual economic participation. And in some key sectors like agriculture, and probably, you know, construction, a bunch of others.

I'm wondering if that's something that's on the radar, or, you know, you're sort of, how are you managing -- how are you paying attention to that to see if it actually is big enough to move the needle?

MR. COOPER: Yeah. Yeah, I agree that I think the way you phrased that was an insightful point, that the actual numbers -- the impact is probably bigger than the actual numbers. And yeah, construction, just anecdotally, of course, I've heard that in construction and agriculture. I haven't discussed this with our agriculture forecaster, so I'd be curious to dig into that further, I guess. I think we're meeting next week to talk about sector forecasts. So it's definitely on our radar. I guess I can't speak to specifically how we're going to -- whether

or how we might make any adjustment for that. I'm not sure at this point.

COMMISSIONER MCALLISTER: Yeah. I mean, there's so much uncertainty at the federal level, and the impacts are really hard to tell. I mean, it seems like things change every day. So, but just curious. We'd love to just hear how that conversation goes.

MR. COOPER: Sure. Yeah. Thanks for highlighting it.

COMMISSIONER MCALLISTER: You bet.

VICE CHAIR GUNDA: Yeah, Commissioner McAllister, to that point, I think I just want to just kind of uplift your question on that one. This has been an active conversation within the JASC process as well on, just to your point, how does the uncertainty propagate downstream? How big are the magnitudes? So there's a few different consultants that are being contacted.

But I think to your point, the staff are starting to look at, for example, all the way from coincidence of loads on the distribution grid, and if there's a megawatt change upstream, how does that flow down, right? And all the way from the variable. So I think there are some uncertainty analysis and the risk analysis that are being contemplated. But I think that's a really, really important point you just made.

It should be Commissioner Baker.

Okay. Go for it.

MR. BAKER: Yeah, I apologize. You asked my question, Commissioner Gunda. So I'm good.

VICE CHAIR GUNDA: Okay. Great. Thank you.

So then I'll pass it to Heidi for the Q&A.

MS. JAVANBAKHT: Okay. We at the moment just have one question in the Q&A.

And Mathew, I'll let you take your best stab at this one. We have some thoughts that Asish or I could add as well.

So the question is from Andrew, and it asks, do you plan to include any long-term adjustment for commercial versus residential load due to work from home or similar post-COVID changes, or is that assumed embedded in the data at this point? Or do you have some other take on this issue?

MR. COOPER: Yeah. Great question.

The COVID years, specifically 2020 and 2021, were definitely impacted quite a bit. At this point, I think there is probably enough data. Basically, we assume, I think, that it's going to be embedded in the data. So we don't have any direct adjustment that we're planning to make as far as, like, return to office policies or anything like that. Yeah. We're assuming that's embedded in the

data, sort of trends from the last several years.

But yeah, thanks. That's a good question.

Heidi or Asish, if you want to add anything.

MS. JAVANBAKHT: No. That was perfect. Thanks.

And there's no other questions. So I think we can move on to Asish's presentation. Thanks, Mathew.

So next up we've got Asish Gautam talking about incorporating new load energization requests to utilities.

MR. GAUTAM: Thank you, Heidi.

Good morning everyone. My name is Asish Gautam, and I'm one of the staff members of the Energy Assessments Office, and I'll be providing an overview of how we plan to incorporate information on energization requests by customers of the investor-owned utilities for this year's IEPR demand forecast.

These energization requests are captured in a data source referred to as a known loads database, so I'll be referring to this data set throughout my presentation. We're looking to use the known loads data as a new source of information to inform near-term load growth for the IEPR demand forecast.

As a way of background, the known loads data comes to us via the CPUC's High DER proceeding. The CPEC's High DER proceeding encourages proactive distribution planning by utilities to meet various goals, including

building and transportation electrification. One important goal of this proceeding is to identify local areas in need of infrastructure investments for future GRC funding cycles. As part of distribution planning, the IOUs are including customer load requests captured through the known loads database for consideration in distribution planning.

Unlike much of recent history where load has been relatively flat, utilities are now expecting an increase in load from customers. Drivers of new load growth include state policies to promote decarbonization in buildings and transportation sector, plus growth driven by specific industries such as the technology sector in the case of data centers, for example. Just an example of load types included in the known loads include residential tract home developments, commercial buildings, EV charging stations, there's some data centers in there, and indoor cannabis cultivation. These new sources of load growth bring new challenges for distribution planning.

In the past, large projects such as residential tract home development or shopping malls or industrial facilities required long-term planning related to land acquisition, building permits, and environmental review. This long lead time for these projects help utilities plan upgrades and investments to the distribution system so that these projects could be energized in a timely manner.

However, the recent load growth, aside from the volume of load energization requests, some of these new load types tend to be characterized by rapid construction time and high load intensity relative to the location on the distribution system. As an example, as I understand it, a commercial EV charging station can be constructed in months but can request over a megawatt capacity.

Next slide, please.

I would like to briefly describe what we've done so far on this project. We worked with staff on the CPUC to issue a joint data request to the investor-owned utilities to collect project-level data from the known loads data set, and we do acknowledge and appreciate the help of CPUC staff in facilitating this data request process. This data set captures requests by utility customers to energize load and is considered to have a high degree of certainty that the projects will move forward.

And again, to emphasize, we are looking at the known loads data to help bridge the gap in load growth occurring in the near term that is difficult to forecast from a top-down system-level forecast using long-term economic and demographic drivers. We plan to apply load profiles and incorporate the known loads data as part of our baseline sales by sector, and also, for a subset of completed known loads projects, we are interested in

studying the AMI data to better understand the trends and have a better understanding of variation in load for some of these customers.

Next slide, please.

Next we wanted to share preliminary thoughts on how we may go about including the impacts from the known loads data in a way that allows us to reconcile the growth that's embedded in the IEPR demand forecast -- the baseline IEPR demand forecast from the perspective of avoiding double counting.

Our recommendation is to compare growth on an annual basis by energy for the major sector category. So this would be the residential class, the commercial class, and the commercial sector, for example.

I have an illustrative table here to kind of talk through what we're thinking about in terms of accounting for growth from known loads. So as an example I'm using the residential sector, like I said as an example. As we go through preparing our baseline sales forecast from the IEPR, we expect the residential sector to have an increase in sales by 1,000 megawatt hours, but when we look at the known loads data for all the different residential development projects, when we add up the capacity, apply load shapes, and translate the capacity to energy and we expect that in, for example, 2027 that there'll be 1,200

megawatt hours of incremental energy for that year, we plan to do is to account for the net difference between the known loads and the IEPR forecast. So, in this example, we would add the 200 megawatt hours of extra energy from the known loads to our IEPR baseline sales for the residential sector.

And this will eventually feed to our -- be an input to our hourly load forecast. And then we also propose that other load modifiers in the known loads database, such as EV charging stations and data centers, be handled using the process we use for the 2024 IEPR.

Next slide, please.

This table is meant to illustrate at a high level how known loads data could impact the IEPR system peak forecast. To prepare this table, what I did was take the -- I summed up the capacity by the different load types, and that's reflected in the second column there called total capacity. And this is for the three different IUs. There's San Diego on the top, Edison in the middle, and PG&E on the bottom.

Basically, again, I aggregated the capacity requested by customers by the date when the requested load to be available to them. So, you can see in 2026, in the case of SDG&E, we expect 88 megawatts of customer load to be coming online, and then the next three columns next to

it, I just kind of did a sensitivity analysis to show, depending on how coincident this capacity coming online is with the overall system, what the impact to system peak could be. So the third column there labeled 10 percent. If we expect 10 percent of the load to be coincident with the system peak, I just took 10 percent of the 88 megawatts, so we would expect that 9 megawatts should be added to the overall system peak. And then similar manner for the other percentiles there. There's a 20 and 50 percent.

The last column, what I did was take the annual growth and peak from our 2024 local reliability scenario. And one of the things that stands out is the capacity we expect coming from the known loads exceeds the growth in the 1-in-10 peak from the 2024 IEPR. So depending on how coincident known load projects are with the utility system peak, known loads could significantly drive peak demand in future -- be a significant driver of peak demand. And so for this reason we recommend that impacts from known loads data be only included for the local reliability scenario. And this is to limit downstream impacts to other proceedings that rely on the IEPR. But given the overall magnitude of customer load, we think that in future IEPR cycles could include the known loads in the planning scenario.

Okay. Next slide, please.

We just wanted to discuss our next steps for the near term. We would like to continue working on processing the known loads dataset. There's some outstanding questions we have. We're trying to get some resolution with utilities. We also want to work with the utilities on a data format and on frequency of getting this data for next IEPR cycles. We're also interested in other sources of load growth, such as the pending loads data, and we think this could be helpful to inform our scenarios in future IEPR cycles. For the long term, we plan to explore new models and tools that can help bridge the IEPR system-level forecast with enough granularity to better support both distribution and long-term system planning.

One area we hope to explore as part of this project is to understand how projects with known loads and other load modifiers such as data centers and EV charging stations can impact local areas, such as the magnitude of load growth or incremental load growth, and how load growth in local areas could change when these local areas peak relative to the overall system and what the implications are for both local and system planning. Internally we're looking to explore funding opportunities and resource requirements to support this.

Next slide.

That's the end of my presentation. I'll take any questions.

VICE CHAIR GUNDA: I just want to say thanks for all the good work. I think there's a lot of great information that's coming from both the IOUs, but also CPUC staff. So I just want to make sure I extend my gratitude there.

I don't have any other question other than just a thanks, and I'm tracking the information you provided. I'll pass it to Commissioner Baker for his questions.

MR. BAKER: Yeah. I have two questions. If the known loads in your presentation are included in the local reliability scenario, does that mean they'll be part of CAISO's annual load capacity area study process?

MR. GAUTAM: Yeah, they'll be part of the TPP.

MR. BAKER: Cool. And then my second question is, just in your informed opinion, you know, which of the percentage sensitivities would you argue are -- let's just say this is gut check, okay -- you know, would be most reasonable? If we know -- maybe I'm tipping my hand here, but if the known load has a high capacity factor, wouldn't we expect to see their coincident contribution to be somewhat higher than 50 percent?

But I'll let you answer.

MR. GAUTAM: That's a great question. Good

point.

Right now I think we see more of the projects from the commercial side, I think about nearly 60 percent for San Diego, just a little over a third for Edison, and just under 50 percent for PG&E. So these sectors typically have a higher load factor than say a residential class, so I would expect it to be higher.

But to be honest, at this point, we're just too early on in our process to make that kind of a determination.

MR. BAKER: Great. Thank you. Excellent presentation.

VICE CHAIR GUNDA: Thank you, Asish.

Let's see. Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. I agree.

Sort of building on what Commissioner Baker just asked, going forward, how sort of dialed in do you anticipate being on the actual load shapes of these known loads? So, what's the nature of the sort of data gathering and assessment that you're doing, just to appreciate where there might or might not be coincident, and try to sort of suss out a relationship between capacity factor or load factor, and then system capacity factor. Individual loads or aggregated loads -- load factor, and how that relates to system capacity.

MR. GAUTAM: Yeah. Thank you for that question, Commissioner McAllister.

So we have received some load shape data from utilities as part of this data request. The bulk -- actually all of them are at the utility service area level, so it's not as reflective of local conditions. So for example a residential development in a coastal area should have a different shape than, say, something in the inland. So these are the things we want to try to address in some of our work, looking at completed projects.

We also are looking at some work done by some of our vendors. Recurve has done similar shape. So we want to look at how we can maybe possibly use some of these more granular shapes that maybe match some of our forecast products more closely.

COMMISSIONER MCALLISTER: Okay. Great. Great. I love that. That's kind of where I was going with this.

And now that we have a pipeline from utilities with the interval meter data, it's not sort of yesterday's data, but a few months aged. But for forecasting purposes, I think we're building that in and trying to, you know, really understand in an increasingly nuanced way how load shaping impacts and, you know, mapping onto that the potential for policies to actually shift those load shapes.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: So I love this advancement. So thanks for your presentation. I love it.

VICE CHAIR GUNDA: Thank you Commissioner McAllister, Commissioner Baker, for both those questions. I think, just continues to reiterate the need for kind of the understanding of coincidence factors and optimizing the planning to both meet reliability and also benefit ratepayers. So really appreciate those questions and insights, but then I'll pass it to Heidi.

MS. JAVANBAKHT: Yeah. Thanks.

So Asish, we have several questions in the Q&A. And the first actually came in before you touched on the pending loads, but I'll repeat the question -- well, so you can repeat the answer, I guess.

So the question is from Charlie Alcock. Will any of the pending load forecasts the utilities are developing be incorporated in the IEPR forecast?

MR. GAUTAM: Our plan is to work with utilities and CPUC staff to look at the pending loads for the 2026 IEPR. For this IEPR, we're sticking with the known loads.

One issue is that I think the known loads data, there's some standardization issue across the utilities are still being worked out. As I understand, there will be -- the process will take most of the year to work through. So we are looking at pending loads, but not for this IEPR.

MS. JAVANBAKHT: Okay. And then I think just a clarification on the table that was on slide five. So this is a question from Sam (phonetic).

Slide five on the peak coincident load impacts appeared to show inconsistent results between utilities in the final column, with PG&E shown with particularly higher numbers. Could you review, explain the final column?

MR. GAUTAM: Okay. Yeah. So the final column is actually not part of the sensitivity analysis there. The final column, the numbers there come from a 2024 IEPR Local Reliability Scenario, and it's just meant to illustrate what the growth in 1-in-10 peak was from the last forecast and sort of comparing it as a sensitivity to the known loads data.

MS. JAVANBAKHT: Yeah. So comparing the CEC forecast values to the utility known load data.

MR. GAUTAM: Yeah. Yeah.

And it's just meant to illustrate depending on how coincident these loads are, the known loads could start to exceed what we had as growth for the 1-in-10 scenario from last year. So that's all.

MS. JAVANBAKHT: Okay. We have a question from Doug Karpa.

If the IOUs provide known loads, presumably they also know which LSE service territory they're located in.

What are staff's thoughts on assigning those known loads to the specific LSE instead of peanut buttering across all the LSEs?

MR. GAUTAM: Yeah. So as part of a data request, we did ask the utilities to provide information where the LSE that's responsible for procurement for these projects. I think the initial look is that there's still some data gaps in terms of there's a lot of missing information on the LSE field. So we do plan to go back and ask the utilities to help fill that gap up. But we are definitely not planning to peanut butter the load growth from known loads to different LSEs. We do want to try to reflect where the load growth is happening and the LSE then would be responsible for the procurement.

MS. JAVANBAKHT: And question from Simon Baker.

How much do data centers factor into the known loads data?

You mentioned, Asish, that some data centers are included in the known loads dataset. Is it a small percentage? And is that because data center loads are still considered uncertain and therefore not included in the known load dataset?

MR. GAUTAM: Great question, Simon. So the known loads only track projects on the distribution side, so there's very little data centers on the distribution --

most in fact, if I understand correctly, are on the transmission side.

It's also not easy to identify data centers in this data. We've tried to look at NAICS (phonetic) codes to identify, but it's still an ongoing analysis for now. I believe Edison does track data centers as a specific category in the known loads, so that's the only LSE utility that we know for sure has data centers in the known loads. So we still have to work and try to reconcile the data centers in the known loads and the broader data center analysis that we're doing with utilities to avoid double-counting.

MS. JAVANBAKHT: All right. One last question.

How are you monitoring -- and this is from Claire Broome -- how are you monitoring known load reported information versus what actually materializes over time?

MR. GAUTAM: Thank you for that question, Claire.

So one of the things we were interested in is looking and trying to understand how completed projects in the known loads have performed, basically trying to compare their AMI data to compare, you know, what the maximum load requested in the known loads and how they've actually performed as shown in the AMI data.

To date I think we have meter IDs from two utilities, PG&E and San Diego. So we plan to do an

analysis this summer to look at how they've actually performed versus the load they actually requested. So there'll be an ongoing work that we plan to incorporate for our analysis for this year's IEPR on the known loads data.

MS. JAVANBAKHT: And just to add to Claire's question, Asish, can you talk a little bit too about, like, monitoring this information and tracking over time? Because this is the first year that we've had this data to look at.

MR. GAUTAM: Yeah. One of the things we also want to explore with the utilities is how to continuously get the known loads data going forward. So, you know, as time goes on, we'll build a track record of information for the known loads that we can sort of go back and do a sample and try to understand how these projects have been doing long after they've come online and energized. So it's just sort of part of future plans that we want to get more involved in. But again, as Heidi mentioned, this is the first time we've gotten this data set, and there's a lot of homework we have to do to try to set that up for the future.

MS. JAVANBAKHT: Thanks.

Sandra, I don't see any other questions, so I'm going to hand it back to you to wrap us up.

MS. NAKAGAWA: Thanks, Heidi, and thanks, Asish,

and the whole demand forecast team.

We're now going to move on to public comment.

One person per organization may comment, and comments are limited to three minutes per speaker. A reminder that while we welcome your comments, we are not able to respond to them during this public comment period. The workshop notice does have information on how you can contact us with any follow-up questions.

So if you would like to make a public comment, please use Zoom's raise hand feature to let us know that you'd like to comment. We will then call on you. Open your line, make sure your audio is coming through, and start the three-minute timer. So please use the raise hand function if you would like to make a public comment on today's workshop.

All right. I'm seeing one so far, and two. All right. Just a second here. All right. Working on unmuting lines.

All right. Claire Broome, I'm going to allow you to talk and ask you to unmute. Can you check your audio, Claire, to see if it is working?

MS. BROOME: Okay. Is it working?

MS. NAKAGAWA: All right. You are coming in loud and clear. I am going to now share a timer, and you will be able to start right now. Go ahead.

MS. BROOME: Thanks so much to the Commission and all the staff, and as well as the CPUC for this really important discussion.

I'd like to return to the importance of front-of-the-meter on the distribution grid resources. We're all aware of the enormous uncertainty facing us and the challenges in having sufficient transmission infrastructure. We're also very aware that transmission and distribution infrastructure are the most rapidly increasing parts of California electricity bills, which are already extremely high.

I'm commenting for 350 Bay Area. We care about the environment. We care about rate-payer bills. I would -- I understand you're looking at this. I'm really happy to hear that, but the potential for front-of-the-meter resources on the distribution grid, particularly storage, to meet local demand locally, it alleviates pressure on the transmission grid, and it is, I would argue, a key tool for getting the load flexibility that you're very interested in. Currently you have a lot of these data but it's very hard to separate front-of-the-meter that requires transmission from front-of-the-meter resources which are on the distribution grid. I hope it becomes possible.

And the other complexity is front-of-the-meter

storage on the DG can be demand modification, but it also can be supply. I recognize these difficulties, but I would urge you strongly to incorporate these resources into your planning sooner rather than later, both to have more rapid interconnections, to have cleaner local resources, and to spare ratepayer accelerating costs.

Thanks so much.

MS. NAKAGAWA: All right. Thank you, Claire.

We're now going to move to Eric Little. Eric, if you can unmute your line and check your audio.

MR. LITTLE: Thank you. Am I here?

MS. NAKAGAWA: Yes. You're coming through loud and clear. I am going to set the timer. Go ahead.

MR. LITTLE: Thank you. So thank you for talking about this very important topic today. My name is Eric Little. I'm the Director of Market Design for CalCCA, and we are very interested in having accuracy of load forecasts.

I think it's very important to reiterate what Commissioner Gunda said early on. I'll say it a little bit differently.

This is a lot like riding a mountain bike on a ridgeline. Any turn too far in either direction has some serious consequences. If we under-forecast, we miss reliability. We miss meeting clean energy standards. If

we over-forecast, we do it at the risk of significantly increased costs to customers. So making sure that we hit that line as tightly as we can is a very important thing for us to do.

The data center load growth has become a very big and very important issue. It's new. It's uncertain. And as Heidi had mentioned, there was a discussion about it at the DAWG. And I'll give you a couple of quotes from presentations from that.

One was from PG&E, and it says, for multiple forecast cycles, forecasts will likely be highly uncertain due to the nascency of the data center technology and markets and due to the complexity of data center projects. Edison noted that of the 43 projects they tracked last year, they increased the likelihood of eight projects and decreased the likelihood of 19 projects, leaving the other 16 unaffected. All of this has serious implications on what we do in terms of resource adequacy.

The question that Doug asked about peanut buttering versus specific costs being attributed to -- well, specific needs being attributed to LSEs, and Commissioner Baker mentioned it early on as well, of not having load shift -- well, not having cost shifting. If we spread that to all loads, it cost shifts. But if we put it on the correct entities, it has serious implications.

The slide that Asish showed had 1630 megawatts of capacity growth from the known loads for 2026. Now what percentage of that is coincident is still to be determined, but when you look at that as a system as a whole, it may not be that big of a deal. But if put on a small LSE, that could be a doubling, tripling, or even more of their load. And if it doesn't materialize, those costs will be borne by those few number of customers, so we need to make sure that we're very accurate in that.

The way to do that? We work together. CEC, CPUC, and the other parties perfecting that load forecast in concert. Getting the information early on. Getting knowledge of what's happening in the known loads and what they can expect to be coming. We think that given the size of that data center, we really need a dedicated workstream to be able to consider those issues together.

So I thank you for taking up this important topic, and I thank you for hearing us out today.

MS. NAKAGAWA: All right. Thank you, Eric.

We're going to now move to Doug Karpa.

Doug, I'm going to open your line, ask you to unmute, to check the audio.

MR. KARPA: Okay. I think I pulled it off. I should be unmuted.

MS. NAKAGAWA: We can hear you. Please go ahead

and start. Thanks.

MR. KARPA: Yeah. No. Thanks once again to various commissioners and staff. It's always great to hear you engage in these issues and share your wisdom with us.

And I particularly was gratified to hear the conversation about affordability and costs. I would point out that there are also significant implications for decarbonization, building electrification, because as rates increase, getting an EV or electrifying a house becomes less financially attractive. So, there's always those knock-on effects. So, I'm glad to see that focus.

I did have two comments. One is a very kind of newbie question, which is from the LSE perspective -- so speaking from Peninsula Clean Energy -- one of the sort of ongoing issues that we have is transparency into how the forecasting process is done. And I'm not sure if there is a single document that lays out the methodology, sort of soup to nuts in a way that we can, like, really, for example, replicate it. And if there is, if you could maybe send it to me, and if there isn't, maybe we should work on doing that, and then possibly having LSEs or stakeholders take a look at that and maybe suggest improvements to sort of more formalize the process. And my apologies if that just reflects my ignorance of how this is done. And the other comment I wanted to -- I sort of want to tag on to

Claire Broome's comment about trying to think about how we get distribution connected in front of the meter resources sort of up and running, because not only do they have significant impacts for transmission planning, but we are also really focused, I think, on a lot of the equity issues that are implicated, because some of the main equity issues around electricity focus on polluting gas plants in disadvantaged communities. Many of those are in local areas.

Getting those retired means we have to have resources to replace them. Now that can either be transmission into the load pocket or in front of the meter distribution connected generation. And so we've been taking a very hard look at the financial aspects of that. and one of the key revenue streams, of course, is resource adequacy. But for small projects, going through the CAISO process can be very difficult.

So we are sort of taking a look at and would invite collaboration from the Energy Commission staff to think about are there ways to make those load-modifying, which is generally a simpler process to do, and then could unlock the finances of those projects, get them built, and then we can start cleaning up air pollution in some of these disadvantaged communities. And I appreciate the conversations we've already had, but I just wanted to keep

that going forward from an LSE perspective, that we are very interested in trying to get those resources online.

Thanks very much.

MS. NAKAGAWA: Great. Thank you.

We'll now go to Roger Lin. Roger, you can unmute and test your audio.

MR. LIN: Thanks, Sandra. Roger Lin. I'm an attorney with the Center for Biological Diversity's Energy Justice Program., and two quick comments.

First, concur with the comments of Claire Broome regarding behind the meter resources. We do need to maximize those local community benefits.

And second, also stress the need for the IEPR process to factor in and plan to aggressively regulate one of the major energy turning points for California and the country which is, as many have mentioned today, data centers and their projected tremendous electricity demand.

They represent one of the most energy and water intensive sectors and are expected to exponentially grow in the coming years. The CEC has estimated that energy demand from data centers will grow 11 percent every year from 2024 to 2040, and if we don't manage this unbridled data center growth and its spur of potential newer continued fossil fuel generation and water consumption, we add significant threats to the climate, air quality, energy affordability,

water availability, grid stability, environmental justice, and wildlife protection.

We appreciate the CEC developing scenarios to analyze this development and request, like, the most rigorous and cautious scenarios and also encourage revising that 11 percent projection based on the uncertainties detailed today.

We look forward to participating further in this process, and thank you staff for all the work on it.

MS. NAKAGAWA: Great. Thank you, Roger.

If anyone else on Zoom would like to comment, please raise your hand, otherwise we will go to the phone lines.

For those who are dialed in on the phone, you can hit star nine to raise your hand and then star six to mute and unmute your phone line.

I'm not seeing any raised hands from phone lines.

Oh. We have one here on the Zoom. So we're going to go to Kanya Dorland. You are able to unmute and check your audio.

MS. DORLAND: Good morning. This is Kanya Dorland with the Public Advocates Office. Can you hear me?

MS. NAKAGAWA: Yes. Go ahead.

MS. DORLAND: So I follow the CAISO transmission planning process and often they determine the need for a

transmission project under an extreme scenario because a certain amount of megawatts cannot be delivered. And this is important.

But at the same time, I often wondered if the load forecast could determine is there any amount of megawatts in a certain load pocket that could be shifted under an extreme scenario?

And so I'm just wondering if that kind of information is provided when you're looking at demand response or flexible potential to the CAISO.

MS. NAKAGAWA: All right. Thank you, Kanya. We are not able to respond to public comment, but we will put the email address for the IEPR into the chat if you do want to have someone follow up with that question.

Last call. If there's anyone else who would like to make public comment on Zoom, please use the raise hand function. If you're calling in on the phone lines, you can use star nine to raise your hand.

I'll give it another few seconds here.

Alrighty. And as a reminder, if you do want to submit written comments, those are due by 5 p.m. on August 20th.

We'll now go back to Vice Chair Gunda for any closing remarks from the dais.

VICE CHAIR GUNDA: Thank you, Sandra, and thank

you for running through the public comment.

And I just want to recognize Claire, Eric, Doug, Roger, and Kanya. Thank you for your comments. I just, you know, wanted to just observe and recognize the importance of the points that you've made from capturing the in front of the meter resources, specifically I think the focus also on the storage and how best to integrate data impact into the load forecast, load modifying, or broader planning.

And another theme that came through was the transparency of the process and the documentation, you know, the coordination. And Eric really recognized the importance of really being sensitive to the forecast and how the breakdown of the forecast could impact smaller LSEs and then the tremendous impact it could have on them.

And finally, Kanya, thank you for raising the point around the opportunity for demand flexibility within the broader transmission planning process. And I think all of them, we are broadly tracking really important comments and thank you for your insights. We are trying our best to continue to quote unquote reduce the silos of kind of different analytical products and trying to harmonize them into a broader framework, all the way from resource planning to reliability. So just know that we are tracking your comments and we are working on them.

Doug, to your point on transparency, much of the products today are public, I believe, but would appreciate you following with CEC staff on the process and how best to engage so we can continue to coordinate on getting input from stakeholders who are really interested in helping improve our products.

So again, in closing, really, really helpful workshop. As always, really appreciate the diligence by the CEC staff, the objectivity, and the focus on making sure we have not just a single point forecast but a lot of different opportunities for scenarios so we can continue to stitch together a planning forecast that really fits the moment in which we are in, and taking information as close to adoption of the forecast as possible. So really appreciate all the incredible work and the tremendous effort by the CEC staff and the colleagues from PUC and CAISO.

And Sandra, to you, your team, we cannot do this workshop without you. Day in, day out, the IPA team is fabulous, a wonderful team, and also want to just extend my gratitude to fellow commissioners both at CEC, PUC, but also leadership at both CAISO and CARB who do work on this, and all the stakeholders who take their time both to come into these workshops but also the dog process, the informal process where so much time is spent on providing input and

back and forth on continuing to improve our forecasting processes.

So again, thanks a lot. Look forward to the public input that will come in and then continue to make the forecast better and better.

With that, I'll pass it to Commissioner McAllister.

COMMISSIONER MCALLISTER: I think you described the moment we're in great, but I just wanted to extend all the thanks to you as well for your guidance and leadership on the forecasting process year in and year out, and really great partnership with you and across the agencies, keeping the IEPR vital and always improving. And just reiterate that staff just really love to see both the rigor, analytical rigor, but also the open-mindedness to new ideas and the ability to sort of incorporate and extend the approach where it makes sense. So I'm very, very interested in seeing where the forecast goes this year and as more data comes in and as you get closer to the final product.

So again, appreciate President Reynolds and Commissioner Baker for being with us and the leadership across the agencies for their leadership.

So back to you, Vice Chair, or perhaps Commissioner Baker wants to.

VICE CHAIR GUNDA: Yeah. I think both Commissioner Baker and President Reynolds had to jump off. So Commissioner McAllister, thank you. Thank you for your comments and thank you for your inputs and insight in so much of the work that we do both on the forecasting, but also the incorporation of energy efficiency into the models and the data side. So thank you, Commissioner McAllister.

Also want to just take a moment to just appreciate former Chair Bob Weisenmiller, who has been such a great proponent of improving our work at CEC. We don't have him anymore, but just a gratitude to him and want to honor his memory in this workshop and as work we do. Commissioner McAllister, how about I just pass it to you if you want to add any comment on Chair Weisenmiller and you can close the workshop.

COMMISSIONER MCALLISTER: Oh, goodness. Thank you. Thank you, Vice Chair.

I won't go into too much detail here, but I really just feel like we've lost a lion of energy policy in the clean energy transition in California. You know, Bob Weisenmiller, former Chair of the Energy Commission, but just a real leader -- more than a leader, really a visionary. You know, he was the rare person who just had both vision, but also had so much detailed knowledge about how to connect the dots and get from point A to point B.

And I personally just really benefited from having him in my life. And I know many, many, many people could say the same thing. He was legendary in terms of his ability to nurture relationships and, you know, send texts at all hours and just remember details, personal and professional of all of us, everyone that he worked with. And I really consider him one of the best colleagues and certainly mentors but also friends that I've ever had, and we lost him too soon. I think, you know, he had a lot of plans, things he wanted to do in retirement, and just really, really sad that he won't be able to do those things, and that we won't be getting texts and emails from him at all hours of the day. I really can't start to get my head around that.

But he -- you know, Bob was right there at the beginning of the Energy Commission, an early staffer, senior staffer for Governor Brown when he was developing and implementing the commission, and then went off and had a consulting career that was very vibrant and largely focused on California during the old PURPA (phonetic) days all the way up through every iteration of energy policy in the state. And then came back to the Commission under Governor Schwarzenegger, and then became Chair, and really was just instrumental in helping me when I came, supporting my coming to the Commission and helping me really get my

sea legs here. And, you know, mine and many, many other lives were just much, much better for having him in them.

And his memory was legendary. He had a photographic memory. I mean, he just was on top of so many issues at once, and so nimble, you know, all the way, just throughout his whole career, up until retirement and even afterwards. I saw him, spent a day with him at the Energy and Resources Group at UC Berkeley's 50th anniversary in May, and just really looking back at that as a precious opportunity because we didn't know we would lose him.

So anyway, I've been thinking about him for the last week since he passed. And I know a lot of people are saddened by our collective loss and California's loss.

Anyway, rest in peace, Bob. It was just a wonderful memory.

Thanks for the opportunity, Vice Chair.

VICE CHAIR GUNDA: Thank you so much, Commissioner McAllister.

And with that I'll pass it back to Sandra for closing. Thanks, Sandra.

MS. NAKAGAWA: Thank you so much everyone.

With that we are adjourned for today's workshop.

(The workshop adjourned at 11:17 a.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 28th day of September, 2025.

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, CERT**367

September 28, 2025