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STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

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

IEPR COMMISSIONER WORKSHOP ON

ENERGY DEMAND FORECAST DRAFT RESULTS

REMOTE VIA ZOOM

WEDNESDAY, DECEMBER 17, 2025

9:00 A.M.

Reported by:
Elise Hicks

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P R O C E D I N G S

9:02 a.m.

WEDNESDAY, DECEMBER 17, 2025

MS. RAITT: All right, well, good morning, everyone. We'll get started. Thank you for joining today's Integrated Energy Policy Report, or IEPR, Commissioner Workshop on Energy Demand Forecast Results. I'm Heather Raitt with the IEPR Team here at the Energy Commission. And this workshop is being held as part of the CEC's proceeding on the 2025 IEPR.

Today we're doing a remote workshop using Zoom. And this workshop is being recorded and the recording will be linked to the CEC's website shortly after the workshop.

So to follow along, the schedule and presentations are posted on our website. And there will be opportunities to ask the presenters questions. We'll have a few moments or a few minutes after each of the panels to take audience questions, but we may not have time to answer all the questions. The Q&A feature is available for you to submit questions. You can just type those in. You can also upload a question by clicking on the thumbs up icon and those that receive the most votes are moved up to the top of the queue.

Attendees are also invited to make comments at the public comments section at the end of the day. And please note that we will not be able to respond to comments today at the end of the day. And the comments are limited to three minutes per person with one person per organization, please.

And written comments are welcome. And the instructions for how to do that are on the workshop notice. And we are requesting that you submit your written comments by 5:00 p.m. on December 31st.

So with that, I'll turn it over to Vice Chair Gunda for opening remarks. Thank you.

VICE CHAIR GUNDA: Thank you so much, Heather, and welcome, everybody, to the workshop today.

I just want to begin by acknowledging fellow Commissioners from PUC and CEC today on the dais. In our tradition this year, we have two participants, two Commissioners fully present and one Commissioner from PUC that's listening right now. So three-two, and they win again. So PUC has been winning all year on the presence.

So I want to thank Heather, Denise, and the entire IEPR Team and today's presenters from CEC, Heidi Javanbakht, Matt Cooper, and Nick Fugate. The entire Forecasting Team has contributed to this work that is going to be shown today, and then comments will be taken, so just want a big thanks to the entire Forecasting Team at CEC.

But also want to recognize CAISO, PUC, and CARB, utilities and other stakeholders who have provided critical feedback throughout the year. There is a lot of changes that have been happening, federal policy uncertainties, policies around electrification, and a number of uncertainties had to be really thought through. And then staff had to work across agencies to make sure we have a credible forecast. So just want to thank all the agencies and utilities and stakeholders who helped us this year.

California’s energy planning efforts depend on strong coordination. And as Commissioner McAllister always says, you know, the forecasting is a core responsibility for the CEC and really starts the overall planning process and underpins that.

As most of you know, there is a single forecast agreement between CEC, PUC, and CAISO, and it’s central to the effort around planning, whether it’s distribution, transmission planning, RA, or IRP. So the forecast flows into a lot of different things and the uncertainty impacts them differently. And so it’s important for us to think through what forecast is used for what purpose.

Again, truly appreciate CPUC and CAISO staff who work on a continued partnership through staff-level coordination called the Joint Agency Steering Committee, and their work is invaluable in steering this overall work.

I want to observe two things. You know, since the last forecast, we really had to think through how to start putting in the data center load into the forecast. So that has been a big improvement last year. And, you know, the utilities were instrumental in providing that information. And we continue to make progress on that. And this year, informed by the CPUC's High DER proceeding and efforts to improve distribution planning, the team is collaborating with PUC and utilities to better capture what is called known loads, and we're going to discuss that today. I want to thank Commissioner Houck and her office for the coordination, and the President Reynold's office as well.

And so overall, I think there's a lot of uncertainty, and this uncertainty plays in a variety of different ways as we move into the planning over the next 15, 20 years. So I really look forward to the comments and, you know, thinking about how best to structure the forecast as we move forward.

With that, I'll, you know, request Commissioner McAllister if he has any comments.

COMMISSIONER MCALLISTER: Yeah, great. Thanks, Vice Chair. I really appreciate those framing comments.

And first of all, I want to thank Heather and the team for putting together all the workshops leading up to today, but including today, obviously, and just amazing professionalism on the IEPR Team. This is, you know, as Vice Chair said, a core responsibility of the Energy Commission.

And so, you know, in 2025, the odd year, usually there would be sort of methodological improvements and the like, you know, on the normal. This year, I think, as Vice Chair said, we focused more on trying to understand the uncertainty rather than sort of tweaking methodologies in a fundamental way, really just layering in some of those deep dives on where significant uncertainty is around data centers and unknown loads. And just want to reiterate the thanks to the utilities and all the stakeholders for helping get hands around that, get arms around those discussions.

I don't want to repeat too much what Vice Chair Gunda said. I'll really toot you on point. I guess I would just say, you know, we often forget, I think, in California, how unique this process is. Other state energy offices and even PUCs and public service Commissioners, you know, across the country, when they find out sort of the depth of our work and knowledge and expertise and analytical capacity and data collection authority, it kind of blows their minds. You know, the vast majority of states depend almost entirely on the utilities themselves to present forecasts for their territories and often have very little ability to look over the utility shoulders and sort of dig into the analyses and understand whether they agree, right, with the approach that the utilities have taken.

And I think it’s really something special in California that we’re able to take the leadership position and develop, you know, the forecast, relatively from scratch every time, and then triangulate extensively with utilities and others to make sure that it’s credible and that it is capturing all of the elements, including the uncertainty that’s emerging today. So I think having that, this brain trust at the Commission and across into the PUC and the Cal ISO really does strengthen our planning and create a solid foundation for understanding where load is going and how to respond to some of the trends. And so I think as a policy matter, this is just really foundational to California’s approach.

So I really just appreciate all the expertise. Certainly we’ll hear from Heidi and Mathew and Nick today, but a huge team, huge, you know, brain trust in the Commission behind all of this work that we’ll hear about today.

So thanks to Commissioners Houck and Baker and Douglas for being with us. You know, I try to represent, but we can only be one person; right, Vice Chair? So we’re stalwarts here. But really I think it highlights just the collaboration and the partnership with the PUC and the importance and the gravitas that we place on the forecast.

So with that, I'll wrap up and pass to Commissioner Houck for any opening comments you might want to make or --

VICE CHAIR GUNDA: Yeah, Commissioner Houck --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- you're muted.

COMMISSIONER HOUCK: Can you hear me right now?

COMMISSIONER MCALLISTER: Oh, there you go.

VICE CHAIR GUNDA: Yeah, we can hear you.

COMMISSIONER MCALLISTER: Great.

COMMISSIONER HOUCK: Thanks, Commissioner McAllister and Vice Chair Gunda. I want to thank the Energy Commission, your IEPR staff for continuing to do such an excellent job on the workshops and the IEPR.

This forecast, as both of you said, is really a critical function to our planning process here in California. And we've been working collaboratively with your offices, particularly as Vice Chair Gunda said, on our High DER proceeding with the planning process here for looking at the demand forecast, which really is important. And we've been talking about things like pending loads and scenario planning and what does that mean and how does it fit in.

We have two resolutions on our voting meeting tomorrow addressing both of those issues. And we've been able to work collaboratively with your staff and working through these issues and are looking forward to continuing to do that. The resolutions, you know, have not been adopted yet, but they do recognize that we may need to make adjustments and we need to be staying in close coordination with the CEC.

So I'm looking forward to hearing the presentations today, to continuing this work and making sure that we have a grid that's going to be able to meet the needs of the 21st century.

And with that, I'll hand it off to Commissioner Baker.

COMMISSIONER BAKER: Thank you, Commissioner Houck. I'm excited to see load growth in the electric forecast. I don't know if everyone has seen the recent LBNL report that really highlighted the states that had some of the highest load growth had some of the lowest growth in electricity prices. And that makes sense. You know, if you can bring down electricity by selling more of it and spreading those fixed costs over more electrons, that can help end users. As Commissioner Houck said, our job at the Public Utility Commission is to design just and reasonable rates to facilitate this kind of beneficial load growth.

I would be remiss, though, if I didn't mention one of the major impediments to, you know, to achieving this kind of beneficial load growth right now, and that's our wildfire crisis. Wildfire is a major driver of cost increases, reliability concerns, and it competes with other critical utility functions such as energization. All stakeholders have an interest in helping the state to address this issue in a comprehensive, equitable manner to reduce the burden on the electricity system. If we're able to do so, we can speed energization, advance our climate goals, and reduce costs.

With that, I won't repeat what everyone else said. I am very excited to look at the future with you all today, and I want to thank the Energy Commission for inviting me here to participate.

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

I know Commissioner Douglas is in a listening mode right now. So with that, I will pass it back to you, Heather, to get us started.

MS. RAITT: Great. So, thanks. So our first speaker is Heidi Javanbakht.

So go ahead, Heidi.

MS. JAVANBAKHT: All right. Good morning. Thanks, everyone, for being here today. Thank you, Commissioners and everyone on the dais. So, I'm Heidi Javanbakht. I'm the Manager of our Demand Analysis Branch.

And I also just wanted to take a moment to add thanks to the Forecasting Team. So at these workshops, you just hear from a handful of staff, and today, there's really just three of us representing the Forecasting Team. But behind the scenes, we have a really large and dedicated team of about 40 people that work on various components of the forecast. And it's really a lot of work to pull this together every year, and it's work that's gotten a lot more complicated with, you know, incorporating the strategies to meet the state's climate goals and digging into the uncertainty around the pace and impacts of electrification and this year around what the impacts of the federal changes to incentives are.

So I just want to echo the appreciation for this team, acknowledge that this has been and will continue to be challenging work, and just show my gratitude for the teams being flexible, considering alternative solutions, taking on new work, like the known loads, and just for being great teammates.

So I wanted in particular to give a shout out to a few of our technical leads. So Nick Fugate, Lynn

Marshall, Chris Kavalec, Asish Gautam, Mathew Cooper, Anne Fisher, Alex Lonsdale, Jeremy Smith, Quentin Gee, Andre Freeman, Nick Janusch, Ingrid Neumann, Ethan Cooper, thank you to all of you and to everyone else on the team for all of your hard work this year. Still more to go, but this workshop today is a big milestone for us.

Okay, so with that, let's dive in. I'm going to start us off with an overview of the CEC's Energy Demand Forecast, just for those of you who may be new to this process.

So next slide, please.

Okay, so why does the CEC forecast energy demand? In 1974, the Warren-Alquist Act established the Energy Commission to respond to the state's unsustainable growth in demand for energy. And as part of this Act, Public Resources Code 25301(a) requires that the Energy Commission conduct assessments and forecasts of energy demand.

Next slide.

The Energy Demand Forecast, which is also often referred to as the IEPR Forecast, is foundational to procurement and system planning in the state. It is used by CPUC and the utilities for resource adequacy requirements, and it's an input to the determination of the planning reserve margin. It's used by the CPUC for integrated resource planning, which drives procurement.

And it’s used by both CPUC and CEC for system reliability assessments. The California ISO also uses the CEC forecast for transmission system planning. And the forecast is used by the investor-owned utilities for distribution system planning.

The next slide.

The forecast is a 15-year forecast of electricity and gas demand in the state, and we project annual electricity and gas demand and hourly electricity loads. The forecast includes scenarios reflecting various levels of adoption of behind-the-meter PV and storage, energy efficiency, building electrification and transportation electrification, and also data centers. And the forecast also includes the one-in-X-year net electricity peak demand estimates.

We update the Electricity Forecast annually with a comprehensive update in the odd years, and the Gas Forecast is updated every two years in the odd years. The final results are posted each January.

On the Integrated Energy Policy Report, the IEPR report includes a forecast chapter and documents the single forecast set agreement between the agencies and the ISO and lays out which set of scenarios is used for each electricity system planning purpose.

Next slide, please.

So on the next few slides, I'm going to walk through the forecast model system just at a very high level.

Next slide, please.

We produce a system-level forecast, and our forecast is for eight electricity planning areas. This includes the three IOUs, Northern California non-CAISO, which we refer to as NCNC, LADWP, Imperial Irrigation District, Burbank/Glendale, and Valley Electric Association.

Next slide.

The common level of geographic granularity across all of our forecast models is the forecast zone, and these are based on planning area boundaries in addition to climate. I'll note that these zones are different than the climate zones used for energy codes and standards.

Next slide.

And I also wanted to just quickly touch based on forecast terminology. We forecast total consumption, so this is before PV or load modifiers are taken into account. And by load modifiers, I mean energy efficiency specifically here. And then when we layer on the behind-the-meter distributed generation impacts, this brings us to the baseline sales. After that, we layer on the impacts of additional achievable scenarios for energy efficiency, fuel substitution, and transportation electrification, and that brings us to the managed sales.

Next slide.

The starting point for the models is the historical electricity and gas sales data reported by the utilities. We add this to our estimates of the historical behind-the-meter distributed generation to estimate historical electricity and gas consumption. And then the historical consumption is an input to the sector models.

Next slide.

Economic and demographic projections from Moody's and the Department of Finance are inputs to the models as well as forecasts of electricity rates and gas prices.

Next slide.

Committed energy programs, codes and standards are taken into account, and we also account for the Title 24 mandates for PV and storage for new construction.

Next slide.

Additional achievable scenarios are developed for energy efficiency, fuel substitution, and transportation electrification. Currently, we are only looking at fuel substitution for the residential and commercial sectors, but soon we will also be including the industrial and ag sectors in the fuel substitution scenarios.

Next slide.

The load modifiers in the orange boxes are combined with baseline consumption to create the managed annual sales forecast scenarios.

And next slide.

The last step is to produce the hourly electricity forecast from which we can extract the net peak demand, and then from here we also estimate the one in X year net peak demand.

Next slide.

Okay, so next, I wanted to talk about the status of the 2025 IEPR Forecast because we are in a bit of a unique situation today coming into this workshop.

So next slide.

We received a number of comments after the November workshop on the draft load modifier forecast results. Some comments were submitted to the docket. Others reached out to us directly, and some combination of both. So thank you to everyone who has submitted comments. Your review and feedback on our forecast assumptions and results are really critical to our forecast process and helps us improve our forecast. I'm going to go over some of the common themes, so this isn't a comprehensive list.

First, we've received requests to include new types of resources in the forecast as load modifiers. This ranges from distribution level front-of-the-meter resources, such as community solar and storage, to load shifting or load flex types of resources. And we continue to talk about this with our leadership and with the other agencies. We agree that these resources could play a role in meeting the state's climate goals. However, we do need more time to think through the challenges, and we are thinking about holding a workshop on this topic next year.

The next topic area here is behind-the-meter PV and storage. We received feedback that our PV and storage projections may be too low, with one reason being that the market is shifting towards a third-party ownership model in light of the federal tax incentives going away or being phased out. However, without data, it is difficult for us to make or justify any changes to this component of the forecast. We'll continue to monitor this and consider updates to next year's forecast.

Data centers continue to be an important topic, as this is one of the top load growth areas in the state. We received suggestions to update the confidence levels, and we are in the process of analyzing updated data from the utilities that could potentially justify changes here. So in particular, there were comments around the confidence level used in the planning forecast for the Group 1 projects, which are the projects with interconnection agreements. Right now, we're using a confidence level of

70 percent, and there's suggestion that that may be too low and that we should increase that, because once they've got an interconnection agreement, those loads are -- there's a lot more confidence in them.

So at this stage of the forecast, we are mindful about making any big changes, though, like I said, we just recently received updated data from each of the utilities on data centers, and we'll be updating the data center forecast to reflect these new data sets. And Mathew will give an update on this during his presentation.

The next bullet here is around the uncertainty with California's electrification strategies due to the shift in federal policy. I'm going to come back to this one on the next slide.

And the last bullet here is about the known loads. We've had a lot of discussion over the last few weeks about known loads. The known loads are the utility energization applications. And I'm going to be spending quite a bit of time talking through this topic in a couple slides, so keep those both in mind.

But before we move on, I want to pause here and say thank you to everyone who has contributed and given us feedback on the forecast this year. Big thanks to CPUC and CARB and CAISO, Cal-CCA, the IOUs for your collaboration and feedback and review of our forecast this year. In particular, I want to thank: Cristy Sanada, Amber Motley, Jeff Billington at the ISO; Matt Coldwell, Nathan Barcic, Donald Brooks, David Miller, Paul Nelson, Jaime Rose Gannon, Brendan Burns, Gabe Petlin, Tyler Nam, Markanday Ravi, Jean Spencer, and Eileen Hlavka at the CPUC; Sam Lerman, Melanie Zauscher, Kathy Jaw, Pamela Gupta, Maureen Hand, Stephanie Kato, and Natalie Lee at CARB.

And I also want to give a shout out Silicon Valley Power, Palo Alto, City of Burbank, PG&E, SCE, and SDG&E for all of the data center information that they shared with us this year on this area in particular continues to be a group effort.

And then I also wanted to say thank you to the transmission and distribution planning teams at the IOUs for their assistance with the known load component of the forecast for sharing these data with us and just for meeting with us to talk about this data set and help us with interpreting it. We've had a lot of questions for the IOUs about these data and continue to work with them to work through these questions.

And in particular, I'd like to thank Jon Bradshaw at PG&E for all of his help with connecting us to the right teams over at PG&E to answer our questions throughout the year, both on data centers and on the known loads.

Okay, so next slide.

Looping back to the last two topics on the previous slide are the strategies to reach the state's climate goals and the utility known loads. Both of these are relevant to the discussion around the forecast framework and the combination of scenarios to use in the planning forecast and the local reliability scenario.

So the planning forecast is used for resource procurement and for transmission planning. The local reliability scenario is used for local studies for transmission planning, and it's also the starting point for distribution planning. The local reliability scenario is higher than the planning forecast to account for increased uncertainty in more geographic, more granular geographic regions. The makeup of these scenarios is determined each year with leadership at CEC, CPUC, CAISO, and CARB, and we document the combination of scenarios for these two forecasts in the final IEPR report under the section called the Single Forecast Set.

So for the most part, this table is the same as last year with the exception of the known loads, AAFS, additional achievable fuel substitution, and AATE, which is additional achievable transportation electrification, and these are the rows in the table with the reddish orange text.

And before I dig into those, I also wanted to highlight that in more recent years, we have had two different baselines for the planning forecast and the local reliability scenario, and that's because the behind-the-meter PV and storage, the data centers, and the known loads are included in the baseline, and different scenarios are being used for those for the planning and for local reliability.

Okay, so I'm going to start at the bottom of the table and talk about AAFS and AATE and those scenarios first. So traditionally, we have used Scenario 3 for planning and Scenario 4 for local reliability. This year, we've dropped down to Scenario 2 for planning and Scenario 3 for local reliability. This change is due to several factors. The first is that the federal incentives for transportation and building electrification have been eliminated, and then also transportation electrification has faced federal regulatory changes as well as federal actions that impinge on California's longstanding ability to regulate vehicle standards granted by the Clean Air Act.

On building electrification, CARB has delayed public deliberation on regulatory concepts and has recently begun alternative approaches to a 100 percent new sales requirement for zero-emission space and water heaters. So with that in mind, it makes sense to use scenarios that have slower growth in the near term and just assume that progress towards the state climate goals may be slowed in the near term, but we do expect that the state will develop and implement new strategies to meet our climate goals.

And then going up to the middle of the table, the known loads row, this has been a main topic of discussion over the past few weeks, and the bottom line is that more information is needed before deciding how to include known loads and if they will be included in the planning forecast and local reliability scenario.

For the purpose of today's workshop, the planning forecast results are presented with and without the known loads, and the local reliability results are presented with the known loads. Because known loads have been such a big focus of discussion lately, I am going to recap some previous presentations from previous workshops around what these are, how our team incorporated them into the forecast, and go over why we are considering including them but why we are being cautious.

Next slide, please.

Okay, the utility known load data are energization requests at the distribution system level. These energization requests are for apartment buildings, single-family housing developments, warehouses, schools, etc. The utilities submit this data to CPUC as part of the distribution system planning, and the data are then shared with our Forecasting Team. This last year was the first year that the data were shared with our Forecasting Team. The data set includes project level data such as capacity, sector, energization date, and then the utilities also shared the load profiles with us that they use for distribution planning.

And last note on this is that the utilities consider the known loads to be high confidence.

Next -- sorry, stay here.

We wanted to incorporate these loads into our forecast this year because of misalignment that's beginning to occur between distribution planning and transmission planning. The magnitude of the known loads exceeds the growth in the IEPR Forecast. And under CPUC's High DER proceeding, the IOUs can exceed the IEPR Forecast for distribution planning with justification such as the magnitude of the known loads.

Transmission planning, on the other hand, is conducted by CAISO and adheres to the IEPR Forecast, and so if these loads are not included in the IEPR Forecast, this could lead to situations where the distribution system upgrades are made to accommodate these new loads, but there's no upgrades made to the transmission system. And this mismatch could lead to delays with connecting new loads, and it could also lead to reliability risks.

Next slide, please.

And this is a summary of the capacity requests by year for each IOU. The main thing I want to point out on this slide is the large amount of capacity requests for PG&E and SCE that look to be coming online in 2025, and this shows there's a backlog of energization requests, especially at PG&E. The dates in this slide are the dates that our forecast team used for the draft forecast, so this spike shows up in the results that Mathew and Nick are going to present later, and this has been one of the key areas of our discussions and review over the last few weeks. We know that these dates are optimistic and that many projects have been deferred, and we are working with the IOUs to update the timing.

And though there is some uncertainty with the timing, I want to emphasize that excluding the impacts of these capacity requests could create reliability risks if we do not include them in the forecast, as we would not have properly planned to have the resources to meet these loads.

And then one last note while we're on this slide is that I'm showing the transportation projects here just to give a full picture of all the requests. However, we excluded the transportation projects from our analysis to avoid double counting with our Transportation Energy Demand

Forecasts.

Okay. Next slide.

So as we've been reviewing the known load results and just the overall hourly forecast results, there are several aspects that we're trying to balance when deciding how to include the known loads in the forecast. As I mentioned previously, the impacts of the known loads exceed what we are forecasting in each sector. And this is important enough to repeat. Even if a portion of these loads come online over the next couple of years, then excluding them could create reliability risks, as we would not have properly planned to have the resources to meet the loads.

Additionally, reliability risks are created by having misalignment between the distribution system planning and transmission planning. On the other hand, we want to be careful about overestimating load, especially in the short term, because it impacts resource adequacy obligations.

This is the first year that CEC has considered using the known load data in the forecast, and it's the first year that the IOUs have compiled these data for our forecast team. This means that we don't have a historical record to look at to develop trends, to inform some of the key assumptions that were made in the forecast. However, even if we did, I also want to note, the past few years have been anomalous with more energization applications than seen previously, more applications than normal submitted to the utilities. So we are working with the transmission and distribution teams at the IOUs to sort through the energization timelines and to validate other key assumptions before finalizing the forecast.

Next slide.

Asish Gautam has presented on the known load methodology at several previous meetings and workshops. So for today, I'm just going to do a recap of that methodology and highlight some of the changes that we're working on, which will not only reduce the impacts of the known loads, but push some of them out to future years.

So I first want to note that a cancellation rate is applied, and that assumption is based on data from the Grid Needs Assessment filed with the CPUC in August, and this is not an assumption that we are looking at changing for the final forecast.

The energization dates used in the results shown today are based on what the IOUs included in their May filing for CPUC. We are in the process of updating these dates with the IOUs, and in particular, we're waiting on a new dataset from PG&E.

The ramp rates are another area where we are looking to make updates. The results shown today have load ramping up over one year. PG&E recommended that we ramp load over three years, which is what they use in distribution planning because this accounts for project deferrals, and we are waiting to hear from recommendations from the other IOUs.

And lastly, we are looking at adjusting the utilization rate. Again, the utilization factor is the project's max load as a percent of the capacity requested. For PG&E, we did an analysis of AMI data this year for previously completed known load projects. We are considering changing this to use the same factors that PG&E's distribution planning team uses. Some of these factors are higher than what we came up with, with the AMI data. Some factors are lower. But switching to PG&E's factors would be consistent with the methodology that we're using for SCE and SDG&E since we weren't able to analyze their AMI data.

For all of these areas, we'll continue to monitor trends as we have more historical data, and we'll refine our assumptions.

Next slide, please.

So we have received some data from PG&E already, and we've done a preliminary analysis that incorporates PG&E's recommended changes, and so this slide is comparing results. In addition to the changes I mentioned on the previous slide, we identified and removed 1,500 megawatts of data center load that was double counted, and we implemented a change that PG&E recommended to discount projects that are 50 kilowatts or less by 50 percent. The new results incorporate the three-year ramp that PG&E recommended, but the one change that is not reflected here are the new energization dates since we don’t have that data from PG&E yet.

So these preliminary updates result in a 48 percent decrease to annual impacts in 2027 and a 35 percent decrease to annual impacts in 2030 for PG&E. This slide, again, is annual impacts. We have not rerun the hourly model yet to see how this would change the peak results. So the hourly and peak demand results that Nick is going to show later on in this workshop do not yet reflect -- they do not reflect these changes.

So this leaves us at a place where, again, we need more information and more time before we can make a recommendation with how to include the known loads in the forecast. There’s a lot to consider and think through regarding the reliability risks. There’s always uncertainty with the forecast, and what needs to be considered is whether the risks to reliability outweigh the uncertainties with this particular forecast component.

Okay. Next slide.

So just to wrap up, I have a few more slides about the forecast timeline, and we'll note that the updates to known loads will need to be made in the next couple of weeks for us to meet the timeline for the January business meeting where the forecast is proposed for adoption.

Next slide.

This slide has the full list of workshops and DAWG meetings that we've held throughout this year. We had three DAWG meetings, and today is our fifth IEPR workshop. All of the materials from these previous meetings and workshops can be found online and covers the updates that we made this year.

Next slide.

And here's more details on the DAWG meetings. You can use this slide as a reference to look up any topics that you're interested in. It will show you which dates those were discussed.

And then, next slide.

So after today's workshop, we'll continue updates to the known loads forecast. We'll also review any comments, make any last adjustments, and post final results by early January. I mentioned we do have data center updates to make as well, and Mathew will touch on that in his presentation next. But we are still targeting the CEC's January business meeting for adoption.

Also, in January, we'll be developing the LSE and BAA tables. With all the data center activity, there's been more interest and questions around these tables. So we are considering holding a DAWG meeting on those forms in January before they are finalized.

And that's it for me. And I can take any questions from the dais.

VICE CHAIR GUNDA: Thank you, Heidi. I had the benefit of many briefings on this issue. I just wanted to kind of, for the record, think this through.

In terms of known loads, can you just explain what is the thesis here? So, you know, when I think about demand forecasting, you know, we do the demand forecasting based on the economic demographic variables as the baseline. And then you're adding the load modifiers that kind of get driven by policy and other changes. So we've always kind of seen that going up and down a little bit over time. But in terms of the known loads, is it just that we are front-ending some of what is going to be in the econ demo forecast in later years, or do we anticipate this known loads to continue as an increment to the econ demo baseline in the long run, or that's evolving?

So can you kind of share? Because I think it's an important part of trying to reflect on the reliability side of it. And I think we want to think through transmission, distribution, IRP, and RA in different contexts. But I think the reliability should underpin the most robust sense of what the loads might be on the system.

MS. JAVANBAKHT: Yeah, I think the answer to your question is that it’s evolving. And we’ll see as, you know, we have a historical record of the known loads as we build that historical record and can look at trends.

But one other key thing that I did not mention in my slides that I should have is that these known loads are incremental to what we’re forecasting in the sector forecasts. So we are -- the reason we’re looking at the annual energy is because if for a year in a sector, the annual energy from the known loads data exceeds what our sector models are forecasting based on the economic and demographic data, then we’re counting that difference in the forecast or in the known load impacts. And so that’s, you know, the slide that I was showing with the estimation of the known load impacts, it’s that difference. It’s not the full impact.

But I think it will be really important for us to continue to receive this data, you know, from the IOUs through the CPUC and to continue to evaluate this to see. You know, with so much load growth happening with electrification and other, you know, just like buildings being -- new buildings coming online, it's just a check, I mean, more than just a check, but a check on our economic and demographic forecasts. And if we do find that we are underestimating load growth, you know, either reassessing our economic and demographic forecasts and that methodology or continuing to incorporate known loads in a similar way.

VICE CHAIR GUNDA: Just one more question and then I'll pass it to Commissioner McAllister and Commissioner Houck. So just on the -- maybe this is a multi-part second question, so I'll not deviate from just having two.

So in terms of known loads, right, so when we have an econ demo kind of contribution to the forecast, I think, A, you know, is to kind of think about when you say incremental, you know, you have known loads, let's say the known loads are 1,000 megawatts and, you know, but the econ demo was 800, whether it's energy basis or capacity basis, and if we say that we are going to take the 200 and add as a premium or an incremental, would it also be an undercount, that's one, you know, or an overcount, you know, just one?

Second, in IRP and resource adequacy, we allow for a certain level of demand cushion, so right about four percent or so, like you have the PRM. And so that cushions the planning a little bit in IRP. Again, that's not from a known loads. That's more of a temperature deviation and others. So let's just kind of say there's a little cushion. Do you have similar cushion on the distribution planning and transmission planning? I do not believe so.

So I'm kind of just thinking through what parts of the planning already does account for certain uncertainty? And could we absorb some of this uncertainty in those today or not? And I think the point to your first point -- your answer to the first question really points to the transmission planning because it's a long-run process.

So just want to see any additional thoughts. And I think we'll have a lot of discussions over the next couple of weeks for sure.

MS. JAVANBAKHT: Yeah. Well, and I'm going to call on Asish to provide his thoughts on this too. But before I hand it to him, I just also want to note that there's a reason we have two different forecasts. The planning forecast is used for resource procurement. It's used for resource adequacy and IRP. It's used for transmission planning. But then we've also got our local reliability scenario, which is really meant for the more geographically granular planning. So it's the basis for local transmission planning. And it's the starting point for distribution planning.

So there is some consideration there for how do we provide space for the grid upgrades to be made while, you know, where maybe we want to err on the side of being a little higher, while with the planning forecast, we, you know, we want to do our best to make sure that that’s what we -- what we’re anticipating, what we expect for resource adequacy and for IRP.

I’m going to -- unless you have something you want to say, I’ll hand it to Asish to see if he has anything to add on your other questions.

MR. GAUTAM: Thank you, Heidi.

So Commissioner Gunda, you made a really good point. And this topic of double counting of impacts has been on our mind. And the sort of the process that Heidi described about how we want to remove double counting of impacts from known loads is one approach we’ve taken. It is based on looking at annual energy. And so there is a way that we have addressed double counting of impacts.

But as to your other point about having extra cushion from broader planning assumptions, that is something we don’t really get into when we look at the forecast from a sector level. I think, as you noted in your comment, a lot of the buffer is really for accounting for contingencies related to weather and outages and things of that sort.

But, you know, we've had a lot of food for thought regarding double counting of impacts. So we do want to spend more time on it as we collect more of this on those data and become more familiar with it going to the next diaper as well.

MS. JAVANBAKHT: And, Vice Chair, you're muted.

VICE CHAIR GUNDA: Sorry. Thank you. Thank you, Asish. I think I don't have any other further questions because I know we'll keep talking about it. But just as a comment, you know, and Heidi, I think you and I had a short conversation on this, I think it's really important for us to think about as we propagate the uncertainty from the starting point of the forecasting process all the way into the build out, understanding what levels of cushion and uncertainty is available and needed for, you know, the kind of both the balancing act of affordability and reliability and making sure, I think, if we are in an untenable situation this year, you know, we recognize that there's large known loads that most likely are going to come in 2025, but maybe not. I think it will be helpful for us to think about what we recommend to PUC and CAISO downstream processes on our recommendation of which forecast scenarios they could use; right? It really comes down to that.

So let us kind of think this through. And I think I want to be super conscious about the liquidity in the market in terms of the total energy supply in California and the West and what that -- how that impacts the RA prices; right? I mean, that's a very important thing to think about. And it's not a but, it's an and, which is also we need to make sure the lights are on. You know, we were lucky three years in a row. We had we had moderate temperatures, you know, and we have good kind of generation coming up in the West, especially in California. So but, you know, if we were under an extreme scenario like '22 and with this known loads coming online or a fraction of them coming online, are we well situated in '26 to make sure the lights are on and then that stability is there?

So, and I think there's a lot of choices we'll need to make. And I really hope that some of the public that are attending today have ideas on how to do this as well, the tradeoff.

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

COMMISSIONER MCALLISTER: Great. Thanks, Vice Chair Gunda. So great discussion.

And I wanted to just have a look at -- this is related to this probing there -- I want to have a look at slide 19, and that's the known loads capacity requests. And I guess, you know, the 2025, like this year, okay, we have a ton of requests, particularly PG&E and Edison. And

I guess I want to get a little more sort of nuance on that. Like, you know, you talked about the runway, the sort of period of actual interconnection for those requests and how you're modeling those, which does, you know, involve multiple years going forward. But I guess is that really -- do we really think 2025 is sort of, bam, tons of requests and then they taper off and, you know, next, it's starting in a month, or will many of those requests sort of bleed over and kind of get deferred?

And I guess I'm just kind of wondering, like to Vice Chair Gunda's point, you know, finding that balance between, you know, overestimating the necessary build out versus underestimating. It seems like, you know, I wonder how you're thinking about that, that sort of probability profile. You know, it's -- do we think we're kind of -- are we erring on any particular side, like kind of running more risk of overestimating necessary resources?

It's really a two-part question. One, I just want to understand slide 19 a little bit better in terms of that huge slug of interconnection requests or capacity requests. And then number two, kind of understanding you're thinking about how this plays out as an incremental resource going forward in future years. You know, is it really separate from the main forecast or, over time, will it kind of will it kind of meld with the historical methodologies?

MR. GAUTAM: Thank you for those questions, Commissioner McAllister. So just a quick note of interpretation for the dates on the bottom. So the way we've interpreted known loads data is that the 2025 represents when in 2025 the customers would like their projects energized. So it's not new requests in 2025. So they have been kind of going through the queue. And as I understand for PG&E, they've had backlogs related to other types of work. I think there's a lot of early years in 2020 focused on wildfires that has left a lot of deferral. And the other change is that --

VICE CHAIR GUNDA: Asish --

MR. GAUTAM: Yeah?

VICE CHAIR GUNDA: -- I apologize. Just, I think, just for the, I think, the clarity, that I think it would really help us to have it discussed. So these are already applications that have gone through the process and have been waiting for energization. And there has been a backlog in energization. And PG&E feels confident that they are able to energize a fraction or a totality of this known load. Is that a fair statement?

COMMISSIONER MCALLISTER: Like in this year?

VICE CHAIR GUNDA: Yeah.

MR. GAUTAM: Yes, that's kind of the approach we've taken based on the energization dates that's in the known loads data. And one of the other things is that there's been enough issues raised with the backlog that, you know, PG&E has issued some new energization timelines related to some -- I think it was AB 50 requiring utilities to do, you know, a more transparent and fair job of meeting customers energization requests.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. GAUTAM: So just a combination of factors that have kind of come together the last few years where 2025 kind of sticks out. But we are expected to get new updated data from PG&E, so we won't see if any of these projects are slipping into 2026 or later on. But as of now, based on the data we have, 2025 does stand out for when these projects are expected to be connected.

COMMISSIONER MCALLISTER: Thanks, Asish. Asish, that's interesting. That's really helpful.

It looks like, Commissioner Houck, did you want to chime in on this? It's likely you have some insight on this that -- from the PUC perspective.

COMMISSIONER HOUCK: Yes, and it was related to the question I was going to ask. So I thought maybe staff could answer together.

So SB 410 is -- and AB 50 required the PUC to come up with energization timelines. And there was a mechanism for the utilities to request additional funding to expedite processing backlogged applications. So I think, and it sounds like your staff confirmed that they took this into account, for 2025, there would be an extremely high number just because they were provided funding and they were given timelines to complete a huge backlog of applications for many reasons, including prioritization of the wildfire mitigation. They have new requirements going forward. So that is supposed to hopefully eliminate or minimize the backlog and get applications processed in a more timely manner.

And I guess one of the questions I have for what you’re looking at in the forecast, given this is the first time you’re looking at these known loads, is how are you accounting for that backlog with that sort of huge number for 2025 as we’re going forward? Are you anticipating that they will be back on track and on time, or is there a certain, I think you talked about, cushion in there? I know you mentioned that there was a significant increase in the application.

So I guess one of my questions is, are you anticipating that there will be this exponential increase or that it will at some point level out to a more predictable increased number after we get through this backlog as you’re looking at the forecast?

And then I know we've had a lot of discussions and there are ongoing discussions about the pending loads. And are you looking to incorporate potentially going forward as we're trying to figure out how to incorporate not just the known loads but the pending loads at some point in these forecasts as well?

MR. GAUTAM: Thank you for those questions, Commissioner Houck. So we have been treating 2025 as kind of expected energization date for these projects. We know PG&E is going to give us -- is expected to provide us some updated data, so we want to see if those dates will move.

And then just kind of looking at the requests in the several years before 2025, you can see it's been building up, growing, trending up. And we're not sure until we get more updated data if, you know, we're going to go back to more manageable levels from the known loads going forward. But it's something we do want to dig into. And we do want to work with utilities to keep getting the known loads data refreshed more often.

And then as far as your question of pending loads, we have not looked at pending loads for this IEPR cycle. But we are considering that for future IEPR cycles as part of our scenario planning. As I understand, the pending load is meant to enable more of a proactive planning on the distribution sites. And we do want to kind of inform that on the IEPR cycle. So that is a plan for the future.

VICE CHAIR GUNDA: Yeah.

COMMISSIONER HOUCK: Thank you.

VICE CHAIR GUNDA: Thank you, Commissioner Houck and Commissioner McAllister. And I think this probably will be more discussion here. And Commissioner McAllister, really welcome. We are BK'd on a lot of these things. So I think we have an opportunity to work through this together.

COMMISSIONER MCALLISTER: For sure. I guess I did have one other brief question, though.

VICE CHAIR GUNDA: Yeah, go ahead.

COMMISSIONER MCALLISTER: I don't know if we are -- maybe you're looking to Heather to see where we are on time. But I guess, I think you were kind of implying this, Vice Chair, but what -- under what kind of conditions? You know, you said you're -- you know, the team Heidi is building will be building a sort of historical record as more -- as this kind of conception of known loads and, you know, future loads that aren't kind of in the base forecast, you know, they're incremental and above. And I just want to flag that risk of kind of overestimating. I mean, obviously, we want reliability, but also we don't want to overbuild and, you know, impact customers from an affordability angle.

So it does seem like there's a bit of a risk of kind of overshooting with this addition insofar as these loads sort of by, you know, by experience and by kind of understanding are reflected more and more in the base forecast; right? So I guess I'm wondering sort of what the plan is as we understand more how many of this will -- how many of these sort of new loads will become -- how will the consideration of these new loads, you know, data centers and, you know, the other loads you're talking about here, be sort of routinized and incorporated into the base forecast? Like over time, what that -- what does that process look like?

VICE CHAIR GUNDA: Yeah, Commissioner McAllister, I just want to add to that question, too. And I think I -- you're -- I think I 100 percent resonate with your kind of thinking here. I think the question for us, I look forward to Asish's response here, is really kind of thinking about, so for example, on the reliability planning, for example, when we do the stack analysis going into a summer, what we've done is we've taken the forecast and then we said the worst-case scenario is at 12 percent deviation, right --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- you know, from the demand forecast because of the heat and fire and other risks. And so we kind of like planned the worst-case scenario of reliability for that reason to de-risk our lights going out. But as you say, that is not a prudent way to, you know, possibly plan for a reasonable build-out.

COMMISSIONER MCALLISTER: Mm-hmm.

VICE CHAIR GUNDA: But I think this is where, if there is a reliability standard and there is, to your point, there is an affordability standard, I mean, what reasonable risk can we take? And I think, you know, what I'm taking away from this, it's unclear. And we have to make some discretionary choice in the near term. And I would, I think, I'm kind of leaning towards putting all the information out and then kind of --

COMMISSIONER MCALLISTER: (Indiscernible).

VICE CHAIR GUNDA: -- calling out that deviation for a year if we think that's prudent to do.

But Asish, I'm asking you, Asish, there's a broader question there.

MR. GAUTAM: Yeah, thank you. So one of the things that we've considered trying, and we did try to look into for this year, is to see if any -- if we can see any trend in our sales data as a result of these known loads projects getting completed. Right now, our sales data is current until June of 2025. And when we kind of looked at it, we did not see any noticeable trend of increase in loads, anything from more seasonal variation or anything from prior years.

But Commissioner McAllister, I think, as we expect these projects to get completed, we want to see how our sales data is reflecting that, which we collect through our QFER data system. And then, you know, going forward, as the sales impact of these projects are embedded in our sales data, that's, I think, how we will sort of consider it to be part of the baseline --

COMMISSIONER MCALLISTER: Yeah.

MR. GAUTAM: -- impacts going forward.

COMMISSIONER MCALLISTER: Okay, that's super helpful. And maybe just one more comment to wrap up, and I want to just make sure that Commissioner Houck and Commissioner Baker have a chance to ask any questions they have remaining.

So, I guess, so I really -- I really appreciate the kind of intentionality of, you know, incorporating this new, you know, new circumstances; right? The world is changing quickly. And I think this is a reflection of just AI and all the, you know, broader societal trends that are driving a lot of this; right?

I guess I'm wondering, I think we need to pay pretty close attention to like the co-location discussion and how many of these loads will actually be -- how they will be impacting the grid; right? It might just be kind of a local interconnection issue, but not as much of an energy or capacity issue, per se, if there's a lot of co-location going on with new data centers, say. If the interconnection challenge sort of gets resolved in different ways at different sites, right, where some of them, yes, the utility responds and gets the capacity and supplies the energy to others, where you're going to have sort of weakly connected interconnection, or weakly connected grid at the interconnection point and some co-location going on.

So, I guess, just, it seems like the context of each site kind of matters, and I don't know how much granularity we'll be able to develop, but it does seem like that potentially mitigates some of the capacity challenges that we have on the system, and so really something to keep track of going forward. I didn't hear any of that in the presentation, but maybe you're already doing that.

MR. GAUTAM: So with the known loads, what we saw was the aggregation of capacity through different types of load types, so between residential development --

COMMISSIONER MCALLISTER: Yeah.

MR. GAUTAM: -- small commercial buildings, and things like that. So, you know, we can expect some adoption of behind-the-meter systems on there, especially for residential and new construction. But, you know, this is a little bit distinctly different than data centers, where it’s a smaller number of facilities but, you know, larger capacity, whereas --

COMMISSIONER MCALLISTER: Yeah.

MR. GAUTAM: -- on the known load, it’s a little bit -- a little bit different. I mean, there are some larger sizes in there, but there’s nothing compared to this capacity requested by individual data centers.

COMMISSIONER MCALLISTER: Okay, so you’re not seeing co-location at data centers, like generation capacity co-located at data centers in some of these new sites, these proposed sites?

MR. GAUTAM: Besides some of the sites having backup generation --

COMMISSIONER MCALLISTER: Yeah.

MR. GAUTAM: I don’t recall --

COMMISSIONER MCALLISTER: Okay.

MR. GAUTAM: -- any co-located generation --

VICE CHAIR GUNDA: Yeah.

MR. GAUTAM: -- projections.

COMMISSIONER MCALLISTER: Okay.

VICE CHAIR GUNDA: I think, I think, Commissioner, I think one filter we already get here is, because this is, most of this is applications to the IOUs for a connection.

COMMISSIONER MCALLISTER: Yeah, right. Okay.

VICE CHAIR GUNDA: That becomes a secondary, I think. I think, you know, but I think it's a fair question.

And, you know, Commissioner Houck, would really like to follow up on this, and I don't know if Commissioner Baker has any questions as well. I think there are two things that was well articulated by Commissioner McAllister, and I think we need to think through is, one, the consistency of approval from the Commission on what is required or what we expect to reasonably come online. I think that's an important element.

COMMISSIONER MCALLISTER: Mm-hmm.

VICE CHAIR GUNDA: And there is an element of pre-planning. So, you know, we know that load is coming. And, you know, for the pre-planning, you know, we need some of these investments to be authorized earlier so that can be ready.

But there's another question here that Commissioner McAllister also raised, which is, while we are being consistent and then making sure we are taking proactive steps to authorize the necessary investments, is the load real? And if it's not real, what do we do? And I think that's kind of a question no matter where it is, whether it’s RA or TPP --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- or IRP, and I think that’s a -- I think we need to align on the consistency of, we think the load’s coming, for sure, it’s just about the timing of investments and affordability considerations that we might use different forecasts for different things. But the certainty of load, I think, cannot be questioned across the -- for -- or cannot be inconsistent across all the different processes.

Commissioner Houck, I don’t know if you wanted to respond now, or we can follow up?

But also, Commissioner Baker, I don’t know if you have any questions.

COMMISSIONER HOUCK: Yeah, and I would say that, yeah, that is something we’ve been grappling with, how do, you know, we know the load is real, and what are the criteria? I think the resolution that we have pending before us tomorrow sets out some criteria that we’re looking at as far as when we would allow the utilities to go beyond the IEPR Forecast and what it would mean for certain geographic areas. So I think we should definitely continue to talk in regards to the pending load part of it.

And then the known load, also, as Commissioner McAllister said, not all applications end up coming to fruition, but we know that we have a lot of increased energization coming forward, and so we want to be really careful to make sure we're able to energize customers, but we also want to be very careful not to over plan and end up with stranded costs.

And so these are all the things we're all trying to balance, and the work you're doing is really critical to how we land on this, because we really want that right balance of making sure we've got a grid that's reliable and able to interconnect folks, but not have customers pay for expanded infrastructure that may not be needed.

COMMISSIONER MCALLISTER: I want to give Commissioner Baker a chance to ask a question if he has one.

VICE CHAIR GUNDA: This might --

COMMISSIONER MCALLISTER: Maybe he's had to step away.

VICE CHAIR GUNDA: This might be CPUC pulling, you know, dragged over our eyes. And I think we had more Commissioners at the start.

COMMISSIONER MCALLISTER: Exactly. Yeah. Yeah.

VICE CHAIR GUNDA: Exactly, and that that --

COMMISSIONER MCALLISTER: We're pulling ahead. We're neck and neck. We're neck and neck.

Hey, I did want to ask briefly, just I know we've got to move on, but is there any sort of additional conversation that's necessary about large loads connected to the transmission grid, maybe that are outside of the IOU interconnection conversation? Are we considering any of -- is there any of that going on, like that are sort of directly, you know, connected to the CAISO grid and, you know, other projects that are sort of part of load, but also part of supply, or part of -- yeah? I'm not quite asking the question I want to ask, but I'll just leave it there because it's more or less clear, I think.

MR. GAUTAM: There are some discussions about how aggregation of some of these loads can impact local transmission planning. So we've had some discussion with utilities on that, but kind of still ongoing on how to reflect some of these in the IEPR, but still kind of early in the stage.

COMMISSIONER MCALLISTER: Okay.

MR. GAUTAM: But, yeah.

COMMISSIONER MCALLISTER: Yeah, no worries. We can follow up on that later. That's kind of a separate question.

But, yeah, Commissioner Baker, go ahead. I think you might be muted.

COMMISSIONER BAKER: I apologize. What you can't see in the background is there's a giant Great Dane that is demanding that I scratch her, but I don't have any questions at this time. I apologize. I had to step out for 10 minutes for a meeting, so I'm back now.

VICE CHAIR GUNDA: Thank you, Commissioner.

COMMISSIONER MCALLISTER: Awesome. Thanks.

VICE CHAIR GUNDA: Yeah, I think the agreement was to just kind of answer the Q&A in writing on the go, so if we're good with that, Commissioners, then we can kind of keep moving to the next item.

Heidi, back to you.

MS. JAVANBAKHT: Okay, well, and then just quickly before I hand it to Mathew Cooper, there was one question in the Q&A that I do want to touch on about whether we'll be publishing another draft of the results after we update the known loads data set. I would really like to get input from all the workshop attendees today on what the best way to do that would be since we are heading into the holidays. We have talked about the potential of doing another DAWG meeting where we present the updated results, but we could alternatively just post results and alert everyone that those are available for review. Open to suggestions here since, again, we're heading into the holidays and want to make sure everyone has a chance to review everything before we adopt in January.

Okay, Mathew, I'll hand it over to you.

MR. COOPER: Hello. Good morning, everyone. I'm going to present draft results for our annual forecasts. And I'll probably skim through pretty quickly through some of this to make sure there's time for Nick's hourly results.

Go ahead and go to the next slide.

Just a list of acronyms.

Next slide.

I'll just go over some drivers for the forecast quickly.

So next slide.

Here are some of our primary inputs and how they changed from the 2024 IEPR cycle. And this is just intended to give a quick directional indication. Obviously, the reality is more complicated than just a single up or down arrow, so we'll look at a few of these more closely. And this is specifically just a comparison to last cycle.

For example, population is still growing this year's forecast, just at a slightly lower rate than previously predicted, so it gets downward arrow. And households are going up at a higher rate than previously predicted.

We presented on economic and demographic inputs at a July DAWG and an August IEPR. You can refer to those for a deeper dive. Overall, economic measures are a little lower over the next few years, but then they return to or exceed previous growth rates for the rest of the forecast.

As we said in those previous workshops, there was a lot of economic uncertainty due to policy shifts, trade disruptions, regulatory volatility. Forecasters were cautious in making big shifts in their economic outlook. This is back in May, and so far that appears to have been an accurate prognosis. So rates are a little higher than previous forecast. Our self-generation grows a little more slowly due to the removal of the investment tax credit.

Next slide.

We have our updated data center model to reflect the latest application data, which grows the forecast. We have the known loads data, which we've been talking about, which adds a significant amount to the forecast. And as we said, the charts that we're showing in this presentation have the previous draft results, not the new lower versions from Heidi's later slide.

Last year, the model for cannabis production was revised to use some new data from California's Department of Cannabis Control. This year was updated again using actual energy consumption from that same department, and the results are pretty similar.

Updated transportation forecast shows lower consumption due to slower sales growth and recent federal policy changes, although the changes to the forecast aren't as enormous. They aren't enormous, not as big as maybe you might think. And in general, changes to annual energy don't look as dramatic as like changes to adoption rates.

Committed savings are a little tricky. The total estimated savings are lower, but rather than increasing consumption, it actually reduces the forecast because there's less resulting decay. I'll have another chart about that.

Additional achievable load modifiers, you can refer back to our November 13th IEPR. Energy efficiency impacts are higher.

Fuel substitution, I believe the PiCS portion is larger, meaning more gas consumption displaced, but the zero-emission results are a little lower, so overall it works out to be similar to last cycle.

And AATE transportation trends are similar to baseline transportation, down a little bit. We also have additional Scenarios 2, 3, and 4 for AATE. So like was explained, we've been considering multiple combinations of load modifiers for the forecast scenarios.

Next slide.

This is just a breakout of some of our primary econ demo drivers, just to show a little more explicitly how they’re a little down in the short term, but kind of return to growth later. And I’m just showing this because consequently you can see that a little bit of that impact in the energy -- annual energy results. There’s some rounding errors that make it look like the calculations don’t add up, but I didn’t want to show too many decimal places because the slide has a lot already.

Next slide.

Here’s, just visually, population in households, our primary demographic variables. The 2024 IEPR showed a return to positive population growth, and the 2025 IEPR is similar, just slightly lower. Households show an increase, which is part of an accelerating trend of fewer persons per household.

Next slide.

For rates, we had sharp increase in recent history. Future increases are a little higher than last year, but still gentler than like the recent historical years. And overall, our modeling suggests the impact of rate increases is fairly modest on the forecast results.

Next slide.

Savings from utility programs is smaller in magnitude than previous years. So, like I mentioned, that would increase sales if these impacts were growing in the future years, but we adjust the forecast according to the incremental effect impact of those savings because the past savings are embedded in the historical data. So since we're past the peak, we're experiencing increasing consumption as the savings decay, and less savings means less decay. This was covered by Usman and Cynthia in a previous DAWG, who explained it better, I'm sure. You can look up their slides.

Next slide.

Okay, so data centers. We received lists of data center projects from utilities categorized by what stage of interconnection the project is in, agreement, application, or inquiry, and we applied some assumptions to turn that requested capacity into forecast demand, same model as last year. The utility projects were originally provided to us in September, and the results that Nick and I are sharing today use that September data.

But I just want to note that we recently received updates, and the new list of projects will be reflected in the final forecast results published in January. So those December columns for PG&E and SCE will be in our results that will be shared or posted, you know, shortly, but not in these slides.

Next slide.

This should look familiar to anyone who was at our last workshop. It's the same slide, just comparing the

September data to last year. A lot more applications than last year, but because of the confidence levels that we apply, the mid-case forecast isn’t hugely bigger than last year. And that will probably be true for the updated December data. We’re still reviewing it.

The next slide has the high case, which does count more of the pending applications and more of the speculative inquiries, so it reflects more of the additional capacity requested. And the December data will definitely increase this one somewhat.

Next slide.

Now look at some results.

Next slide again.

So this is similar to what Heidi already shared. We have mid and high cases for baseline consumption sales, and here are the differences, data centers and known loads. And for sales, we have different scenarios because we forecast -- our models forecast consumption, and then we subtract self-generation to get to sales.

Next slide.

Okay, so finally, here are our draft results for baseline electricity consumption. We have the mid and high cases in blue and orange, respectively. The solid lines are this year’s forecast. The dashed lines are last year’s mid and high forecasts. So you might notice initially there’s more distance between the scenarios. Last cycle, it was like 5 terawatts by 2045 -- terawatt hours, sorry. This year, it’s 37 terawatt hours. And it’s because last year we didn’t have the known loads and this year we have -- you know, we’re counting more data centers in the high case. And, again, this isn’t final. Those, both of those, will be revised.

Mid-case consumption is a little lower in the first part of the forecast, which is due to that more pessimistic economic outlook that we described. And a lot of that shows up in the commercial sector. We also applied a slower ramp rate to our -- we used a slower assumptions for ramping for our data centers in this version. I think our updated data that we’re receiving from utilities has some more detailed information on ramping. So we’ll be looking at that and possibly incorporating that, also.

So even though this mid-case is a little lower than last year, it still definitely represents a significant rise from the history in the dashed gray line. So, you know, electrification and data centers are still expected to grow consumption by quite a lot.

Next slide.

This is the sales, electricity sales, which is pretty similar to consumption. The trends are similar anyways. Yeah, so the distance between the scenarios is just slightly higher because of our different self-generation forecasts.

Next slide. One more.

And these are our economic sectors and the type of modeling we're using. So a lot of work goes into each one of these, although I'm going to go through them pretty quickly today. The impacts of transportation, data centers, program savings, and other adjustments are forecast separately and added on top of these models to get our final results, which is what I'm showing in these charts with the final forecast for each sector.

We tried to avoid any major methodological changes this year, as the Commissioner noted, but there are a few minor changes. We have a more robust way to calibrate the residential end-use model. We have an improved econometric model for the commercial sector that predicts energy per square foot of floor space, more similar to how the end-use model works. And the commercial end-use model is still being revamped, but it will be used next cycle. And for the ag sector, we have the new cannabis data that I mentioned. And we're also doing a very small adjustment for climate change in the overall ag forecast.

Next slide.

So this is just an overview of our residential calibration. I won't talk about it much here. In the past, we've scaled the end-use model to a recent weather-normalized historical data point. This year, we continue to do that. We also used a principal component analysis to adjust the individual end-uses based on more years of historical data. PCA is a statistical process that allowed us to identify the causes of variance in residential consumption in terms of the modeled end-uses. There's a DAWG presentation and a technical paper going over this, if anyone wants more details.

Next slide.

So here's the results for the residential sector. This is one that's growing more significantly. Consumption is higher compared to the 2024 IEPR, and that's due to the increase in overall number of households, or a decrease in persons per household. The growth for the very first year of the forecast is a little lower, you can see, but it picks up pretty quickly. And for last year's IEPR, mid and high cases were the same. The 2025 IEPR has the known loads in the high case, although that's for the IOU territories only.

Next slide.

So that near-term economic uncertainty is seen mostly here in the commercial sector, and also somewhat in the industrial sectors. The last historical data point, 2024, also had lower consumption than what the previous forecast predicted. And then there's the more conservative ramping assumptions, which I mentioned earlier.

But the high commercial forecast ends up being much higher in the long-term, again, due to known loads and new data center applications. This high case does discount the applications inquiry still, you know, based on the probability that they'll get built, but even those discounted numbers have a very big impact on the forecast. The difference between the blue and the orange line is about 29 terawatt hours; 17 of that's data centers, 12 is known loads. But again, like we mentioned, those will be revised, so it won't be the exact numbers.

Next slide.

A similar story for manufacturing. Manufacturing output had a downturn in the data. I'll probably just skip over a few of these in the interest of time.

So if you could go to the next slide?

Mining and construction, sometimes we group these together, but I have them separate here.

Next slide.

Agriculture, including cannabis production, water pumping, I mentioned that already.

Next slide is TCU, which is transportation, communication, utilities, transportation just referring to non-motive power, like energy associated with transportation activities, and that grows kind of just with population.

Next slide.

This chart just shows a stack of consumption for each sector. So you can see that, kind of historically, residential and consumption have been similar, sort of neck and neck. But in the near -- you know, in the mid part of the forecast, consumption grows pretty significantly, and that overtakes residential as the largest share.

Yeah, next slide. Next slide.

And I'll look at self-generation again. So, solar PV is the largest component of self-generation. So removing the investment tax credit decreased the self-generation forecast compared to last cycle. This was discussed in previous workshops by the Distributed Generation Team. We have here the mid case in green and the low case in orange, yellow-orange. And just, again, keep in mind this shows energy generated, not capacity or new installations, which would show the impacts more starkly, so annual energy just grows more slowly than it would otherwise. And also note that the low self-gen scenario goes with the high sales case because it offsets less consumption.

Next slide.

This is that same self-generation chart flipped upside down and then with the sales added on top. So in this context, you can see that self-generation is quite significant overall. Sales would be much higher without it. But changes to the self-gen forecast this cycle aren't really driving the big changes in sales, despite the ITC going away.

Next slide.

Now we'll look at a few scenarios for managed sales.

Next slide.

So here's the combinations that were considered. As Heidi mentioned, the planning alternative, with or without known loads, is what the planning forecast will use. So right now we have -- last year's forecast is the dashed blue line. The solid blue line is this year's forecast if we use the same combination. And the green line is the alternative planning scenario combination with the lower load modifiers. And then the brown line is if we added known loads back into the planning scenario.

So lower baseline sales, increased AAEE, decreased AAFS and AATE, all make the planning scenario lower than the previous cycle. Although the known loads would, if we included them, would push it up in the short term.

Next slide.

So similarly, we have two versions of the local reliability forecast, both including known loads but with higher fuel substitution and transportation, and one with slightly more conservative versions. And some of these load modifiers for local reliability were also smaller than in the previous forecast, but the addition of the known loads eclipses them. So for our final versions, I'm not sure exactly where these scenarios will land. Hopefully, it will be something close to this. The known loads are being revised downwards. Data centers will be revised upwards. So there will be some -- they'll offset each other to some degree. I think it may end up being a little lower than what's shown here, so a little closer to last year's.

Next slide.

Just for context, here's the alternative planning and alternative local reliability scenarios on the same chart. You can see the difference between them is larger than in past forecasts. Adding the known loads to the planning scenario would make the scenarios closer together at first, but they still diverge.

Next slide.

This shows the impacts of just the load modifiers for traditional planning scenario versus our alternative planning scenario, with the yellow gold line showing the net impacts. So you can see the impacts of the alternative are more modest or they're even negative in the earlier years.

And the AATE shown in green here is the amount incremental to the baseline transportation forecast. Baseline has, you know, a significant amount of transportation electrification already. I think it goes to almost 80 terawatt hours by 2045. So the AATE scenarios here add another 30 to 50 terawatt hours on top of that. So kind of like what I said about self-generation, the changes to federal policy have impacts when you compare to last cycle, but we're still forecasting very significant growth for transportation.

Next slide.

Same thing here, but for our local reliability, traditional and alternative scenarios. And this is, again, just looking at the AA pieces, not the data centers or known loads.

Next slide.

So now I'll switch to annual gas sales. So for gas consumption is equivalent to sales since there's no self-generation. And we also have only a single baseline scenario since all of our mid and high differences apply only to electricity.

Next slide.

The gas forecast is done every other year, so we're comparing to the 2023 IEPR. I made a mistake on some of these slides by referring to 2024 IEPR. It should say 2023, so apologies for that. The most recent historical data shows lower gas consumption statewide. That and the lower economic projections cause the baseline forecast to be a little lower, but still relatively flat.

Next slide.

Sector modeling techniques are usually similar between gas and electricity. A few differences. We didn't do the PCA for the gas, residential gas end-use model, but we still calibrate it to recent historical data. And we may implement the PCA in the future.

Actually, there's a mistake on this slide as well. We didn't use the new econometric model for commercial, we used the previous version, so not energy per floor space, but the total results wouldn't -- aren't that different anyway.

So next slide.

So if you remember, for electricity sales, also had in the very first year of the forecast, there's a little bit of a lower growth rate. And that may be due to like personal income slowdown. You can see that a little more pronounced here. But the growth picks up pretty quickly because of that increase in the number of households.

Next slide.

For the commercial sector, we have a leveling off and then a little bit more of a decline in the growth rate. And this downward curvature is probably caused by rates growing faster than commercial employment. That was also sort of present in the electricity forecast, just the growth rates were higher there and it got masked by data centers and known loads anyways.

Next slide.

I'll skim over these quickly. Also, this is similar to last cycle.

Next slide.

Mining and construction. This sector tends to depend on like sometimes big project coming on or offline. And I think this recent historical drop may be related to oil and gas projects.

Yeah, next slide.

TCU gas sales also correlated with population, so just a slightly slower increase. And again, these text boxes should have said 2023 IEPR, so sorry about that.

Next slide. Almost done here, so a couple more slides. Go ahead to the next one. So, if we used our planning -- oh, sorry, one back. Thanks.

If we used our planning scenario combinations from the electricity forecast and applied them to the gas forecast, this is what the results would look like. So if you remember on the baseline slide, baseline gas sales were slightly lower but fairly flat. So these load modifiers, they just decreased the gas sales over the forecast period. The colors, we tried to make them the same as what we used earlier with traditional planning scenario in blue and the alternative in green.

Next slide.

Same idea here showing the impacts of local reliability. And the difference between planning and local reliability sales for gas would be smaller than the difference between the electricity scenarios.

And next slide. I think that's it.

Okay, sorry for speeding through that, but happy to take questions. Or actually, I think we'll go to the dais first; is that right?

VICE CHAIR GUNDA: Yeah, Mathew, thank you for the presentation, again, as a benefit of a lot of these discussions.

Can I just make sure that I put one thing on the record as, you know, and just kind of stakeholder? You know, what is the -- in each increment of the data center load, like and as we have different vintages of information coming to us, is it my -- is my understanding correct that the Group 1 of the data center load has significantly grown in the last couple of months?

MR. COOPER: Yes. Yeah, that was the slide that should the change from PG&E and SCE, the three stacked bar charts. Yes, the Group 1 agreements grew for PG&E. Although, I think the Group 2 agreements, there were some dropouts -- sorry, Group 2 applications, like pending applications, show some dropouts.

VICE CHAIR GUNDA: Yeah. And, Mathew, just kind of making sure on that one. So the Group 1 are the applications received, engineering studies are done and you're essentially ready to go, but we still give a haircut to that; right? And the haircut is what percent?

MR. COOPER: Yeah. For the mid case, I think Heidi mentioned this, we are -- in these results, we have 70 percent of the capacity of those agreements in the mid case and have -- and are considering -- we're revisiting that number. In the high case, 100 percent of the agreements are counted.

VICE CHAIR GUNDA: Got it. And then the high case is used for the local reliability?

MR. COOPER: Yeah.

VICE CHAIR GUNDA: Got it. Okay, so -- and is there a specific scenario that's used for DRP distribution planning? Is it essentially local?

MR. COOPER: Yeah, I think so.

VICE CHAIR GUNDA: Okay.

MR. COOPER: Yes.

VICE CHAIR GUNDA: And so, I mean, I'm kind of just -- you know, first of all, I want to thank the IOUs and the CCAs, everybody who's been providing us. And, you know, SVP has been tremendous as well, just the data that we get. But I do want to acknowledge that, you know, to the extent that we are receiving that information as Group 1, 2, and 3, the utilities are in the best place to tell us which group that is in, right, I mean, the accuracy of the validity of that information. Okay.

And I think that's -- again, it kind of ties the thread between Heidi's presentation and yours on some of this information, I think, you know, whether it's known loads or this, there is a certain level of credibility based on how far into the process these projects are and, you know, what level of discretion or what level of assumptions are we going to use in terms of, you know, whether it's ramp rate, whether it's a utilization and so on. So I think the -- yeah, I think let's kind of land on the final results. And I think there will be a lot of back and forth we probably need to do on finalizing the forecast.

But, Mathew, I know how hard you and the rest of the team are working on making sure this is as good as possible in terms of the data, so thank you for all your work. I don't have any further questions. Thanks for clarifying that on the record.

And Commissioner McAllister, do you have any questions?

COMMISSIONER MCALLISTER: Yeah. I think just one, and maybe two.

So just thanks, Matt, for this. This is, I mean, a ton of information. I'm sort of like going through it really quickly. And I know trying to conform with the time requirements here is hard. But so much work behind all of this information, so just thanks to you and the team for the completeness.

Let's see. I guess I really appreciate the mapping of the electric scenarios over to the gas side, you know, as we do, particularly around fuel substitution from gas end-use devices to electricity. I kind of wanted to invite a little bit of -- I mean, it looks like the effects aren't, you know, huge. But I wonder in terms of AAFS, could you help us understand kind of how the various scenarios -- I mean, obviously, this is a conundrum of our time, right, is how to plan both systems to be reliable and safe and manage costs on both sides as sort of we see the decline in gas consumption over time, which seems modest right now, but also, you know, trying to plan for relatively larger scale electrification of buildings, you know, residential and commercial buildings.

Any observations about sort of how that's going and sort of how much the fuel substitution is currently and, you know, the range of possibilities around, you know, what happens if we're really successful, say, with our programs to get people to, you know, convert end-uses to electricity, what the impact on the gas system is going to be on that?

MR. COOPER: Yeah. I'm not the specialist in this area, so I may call on Quentin, Nick Janusch, or one of his team --

COMMISSIONER MCALLISTER: Okay.

MR. COOPER: -- if he wants to jump in. You know, I would say that the decline is steady if you applied those planning or local reliability scenarios to gas. You know, it does displace a significant amount. The baseline forecast was flat. The managed, quote, unquote, "managed gas sales" were sort of like, you know, steadily declining.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. COOPER: Yeah, in general, I think those are also sort of the more mid-case scenarios. And I think, as Ingrid and Ethan presented at the previous workshop, you know, they had less conservative and even like very, very aggressive scenarios for that substitution.

COMMISSIONER MCALLISTER: Mm-hmm.

MR. COOPER: I didn't put together charts with those results --

COMMISSIONER MCALLISTER: Okay.

MR. COOPER: -- although we certainly could if anyone's interested in that.

COMMISSIONER MCALLISTER: Yeah, just if either, if Quentin or anyone else has anything to add there?

COMMISSIONER MCALLISTER: I'm sure like Quentin and Nick are going to add here. I mean, I just want to offer one consideration for us to think this through.

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: I think at a Commission level, I think there has been a pretty solid concern around over-investing in potential stranded assets on the natural gas side.

COMMISSIONER MCALLISTER: The gas side.

VICE CHAIR GUNDA: And I think that's where you're connecting to. I think that the question --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- to borrow a phrase from the petroleum side, like this kind of phase of transition has both uncertainty and requires this dual investment. And I think what is the right amount of investment seems to be the question of the day and how best to articulate that. But, you know, I just wanted to add that and pass it --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- to Quentin.

COMMISSIONER MCALLISTER: Also, just to mention, you know, the -- I guess it's AB 1221, I think, that Commissioner Douglas is leading at the PUC, I know she's not on to comment, but I want to just commend her and the PUC on getting going with that and sort of really exploring the possibilities around the gas system and sort of its future and just kind of figuring out what the optimal path there is in terms of investment.

MR. GEE: Yeah. All great points, Commissioners. So, yeah, my name is Quentin Gee. I'm the Manager of the Advanced Electrification Analysis Branch. We do the -- our team does the additional achievable fuel substitution, which is -- and additional achievable energy efficiency, which is --

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: -- responsible for much of the decline in managed sales. So the AAEE, or additional achievable energy efficiency, and AAFS, or additional achievable fuel substitution, those are two load modifiers that are used for, primarily for, electricity system planning to capture different regulations, market transformations, types of things that could occur in these spaces. They do have implications for natural gas demand; right? So if, you know, if there's, you know, 50 percent more heat pumps, then there will be a lot less gas consumption; right?

So, yeah, we produce six scenarios for EE, for AAEE, and six scenarios for AAFS, and those are used. We are proposing using AAFS2 this year for the load modifiers, so a little bit less aggressive in terms of the fuel substitution that we expect. There are some implications, you know, as Mathew showed and as we showed in our slides, there are implications for overall gas system demand associated with that. However, we currently -- the gas demand implication, or the sort of resulting gas demand, is not something that we currently use for gas system planning. That's done by the natural gas report.

COMMISSIONER MCALLISTER: Yeah.

MR. GEE: So, you know, it's a good balance; right? Because if this electrification does emerge, so the framework that we have for additional achievable is that these are reasonable to occur. This does not mean these definitely will occur. These are things to sort of build in the sort of resiliency that we need for electricity system planning. It may very well be that it does not unfold exactly as expected, and so there could be gas system impacts. So it's kind of like, you know, putting your eggs in one basket or something to that effect.

So there is a balance to be struck here with exactly what the implication is for gas system planning. As we have more confidence and those things maybe can get built in, you know, maybe there should be more of an impact there when it comes to gas system planning. But at this point in time, we're sort of using regulatory drivers and market transformation, expected market transformation impacts that still have a certain degree of uncertainty at this point in time, but we think sufficient for system electricity system planning.

COMMISSIONER MCALLISTER: Okay. Okay. That's helpful. And obviously, much of this is PUC terrain, and I don't want to, you know, I don't want to sort of tread too heavily on that because rate making is, you know, sort of the structure of capital investment and, you know, all the operational challenges that the utilities face, the investment utilities, and, you know, all of them, but the big investments, certainly, that feeds into sort of the big rate work that the PUC does.

But I did want to just look at slide eight real quick and just recognizing these are in 2024 dollars, but the upward tick in at least some of the average electricity rate projections. And I think, you know, I've been saying, I think many of my colleagues have been saying that, you know, we're kind of in this messy middle where we're, on the electric side, where we're maintaining a lot of older investments and we're sort of building out furiously. And so we have this agglomeration of costs that are sort of in the near term, keeping rates a little bit elevated, but that over time, we kind of get over that hump and things start to decline as we sort of are able to retire the older, you know, in many cases, more expensive infrastructure, supply infrastructure.

So a little surprised that the out year is not going down more than that. And I guess just invite any comment on that and sort of how you're modeling that in the out years.

MR. GEE: Yeah, so for AAFS2, the scenario we're recommending for adoption, the adoption is not as aggressive as we had last year, which was more associated with a zero-emission appliance standard that would have --

COMMISSIONER MCALLISTER: Well, I guess, Quentin, I'm just, I'm actually looking at slide eight --

MR. GEE: Oh, sorry.

COMMISSIONER MCALLISTER: -- Mathew's slide eight, which is more of a general question about rates, not particularly --

MR. GEE: Oh, okay. Let me --
COMMISSIONER MCALLISTER: -- not specific to the load modifiers.
MR. GEE: Do we have slide eight available?
COMMISSIONER MCALLISTER: It's just the four, the four, residential, commercial, industrial, ag. Let's see.
MR. GEE: Yeah, so we see, yeah, like you said, that sort of hump. I believe Lynn Marshall could speak to, yeah, that. Oh --
MS. MARSHALL: Yes.
MR. GEE: -- it's hard to see with the slides that are online here versus the slides.
COMMISSIONER MCALLISTER: Yeah. Yeah.
MR. GEE: But Lynn can speak to the downward sort of --
COMMISSIONER MCALLISTER: Yeah, Mathew's slide --
MS. MARSHALL: Right.
COMMISSIONER MCALLISTER: -- slide eight.
MS. MARSHALL: Yeah, and you're expecting, why doesn't it go -- you know, we do have rapid growth in the sales forecast, so why doesn't the rate forecast --
COMMISSIONER MCALLISTER: Yeah.
MS. MARSHALL: -- go down more?
COMMISSIONER MCALLISTER: Yeah.
MS. MARSHALL: We are including costs of --

COMMISSIONER MCALLISTER: Yeah, there you go.

MS. MARSHALL: -- data centers, costs of distribution upgrades. We were using some studies on, you know, the distribution level costs, very preliminary estimates --

COMMISSIONER MCALLISTER: Mm-hmm.

MS. MARSHALL: -- of the transmission impact costs of data centers. Those, both of those, could be revised. Some could be revised downward. But, you know, we are seeing just a lot of growth in distribution revenue requirements in the near term. A lot of, you know, additional spend because of wildfire mitigation.

COMMISSIONER MCALLISTER: Mm-hmm.

MS. MARSHALL: That's starting to slow. So you see residential.

COMMISSIONER MCALLISTER: a little bit

MS. MARSHALL: If we looked at PG&E rates, you'd see, you know, it's, you know, starting to dip a little bit.

One note is that in this forecast, it did include some updates for LADWP, notably, and some other POUs. And the LADWP rate forecast is quite a bit higher because it's reflecting their pending or proposed rates to implement their LA100 plan. So that could, depending on what the board adopts, could be lower.

But, yeah, with all of the spend that's planned, in particular in the near term, to upgrade the grid, we don't see rates declining like you might expect.

VICE CHAIR GUNDA: Lynn, can I just follow up on that question? And just, I know that PG&E has been working through Rule 30 for some of the data centers.

MS. MARSHALL: Mm-hmm.

VICE CHAIR GUNDA: Is that taken into account at this moment? Are we still waiting for it to play out?

MS. MARSHALL: There was some very kind of rough numbers that PG&E put out, and this was described at one of the -- I discussed this at an earlier workshop, on sort of what the cost per, you know, megawatt of the transmission upgrades.

VICE CHAIR GUNDA: A gigawatt is like about a percent; right? Yeah.

MS. MARSHALL: Yeah. And so based on that, I built out transmission revenue requirements in there. It could be on the high side; right? I didn't want to be, you know, overly optimistic about what that would cost. But we just don't have good data at this point. So, you know, hopefully in the next, you know, year, two years, we'll start to get out of Rule 30 and rate cases some, you know, more hard data. That was a very preliminary estimate.

VICE CHAIR GUNDA: So, Lynn, maybe just one other question and I'll pass it back to Commissioner McAllister. And I see Commissioner Houck and Commissioner Baker might have questions.

Just clarification. The Public Advocate's Office does their work on the rate forecast and such. Are we kind of consistent or departs? How do you see that?

MS. MARSHALL: Well, so what they have done is their D-GEM model has been modeling the cost of distribution upgrades to support, you know, electrification, so we've been leveraging that. And they have a new version out, so we'll use that for the next cycle. They don't explicitly do a long-run rate forecast, but we do use their analyses where we can.

VICE CHAIR GUNDA: All right. Thank you. Thank you.

I'll pass it to Commissioner McAllister. And I see Commissioner Houck's hand up too.

COMMISSIONER MCALLISTER: No, I think I'm good. I appreciate your question about alignment with the Public Advocate's Office of the PUC. And, yeah, I'll pass it to our PUC colleagues.

Commissioner Houck?

COMMISSIONER HOUCK: Yeah. No, thank you. And this may be more a PUC issue, but are you working with us to look at, as we're going forward, especially into those later years, how demand flexibility and real-time pricing is, and just even more efficiencies? I know California's bills have gotten higher, but overall we have more efficiencies in our appliances and what we're doing. And so bill impacts may be slightly different than rate impacts, depending on how and when people are using electricity. But how or are you able to or have you incorporated potentially expanded use of demand side of flexibility into the numbers here?

MS. MARSHALL: Yeah, that's not something we've incorporated yet. You know, and obviously, we have a team looking at flex strategies. It's not something that's firm enough that we put in our forecast. But as those, you know, policies and programs evolve, then we would want to start including them in our forecast.

COMMISSIONER HOUCK: Thank you. That's helpful.

VICE CHAIR GUNDA: Commissioner Baker, did you have a question or comment?

COMMISSIONER BAKER: Yeah, I have a dumb question first on slide eight that was raised. I'm assuming those are inflation adjusted numbers, not nominal numbers; is that correct? That would make the most sense.

MS. MARSHALL: Yes, those are. Those are real. Yes, it would look much worse if they were nominal.

COMMISSIONER BAKER: Yeah. And then the second question on a little bit of a different matter is, you know, in previous IEPRs, and really kind of in this one as well, we're always kind of like a year out, a year or two out kind of from more load growth. Is a lot of that -- and I get there's a ton of uncertainty in that. But how much of that is the result of behind-the-meter generation versus load not necessarily materializing? And I'm not sure who to direct that to, so --

VICE CHAIR GUNDA: I think Mathew will take that probably as a starter.

MR. COOPER: Yeah, great question. You know, we've been, some of our staff have been digging into sort of reviewing past forecasts and thinking about that, and I don't know if I have a definitive answer. I'd be nervous to give a sort of black and white answer to that. I know the thinking sort of nationwide is that we are sort of turning a corner from the sort of recent decades of sort of the impacts of energy efficiency, sort of the low-hanging fruit has been gathered and consumption is expected to sort of return to growth along with population economic growth. If you're talking specifically about the last few years, you know, there has been a lot of uncertainty, I would say.

So, yeah, I don't know if I have a great answer to that, but I would open it up to any other staff who want to comment.

VICE CHAIR GUNDA: Yeah, Mathew, maybe one piece, and then kind of request others to add on too.

Commissioner Baker, I think one of the pieces really, at least as I was working in the staff and then in this role is COVID impacts were pretty crazy in kind of adjusting both during and post. I think it's a significant impact. I think that had a real impact on the household flow, you know, whether it's economic demographic variables have been very uncertain because of the, you know, post-COVID era. And I don't think those metrics have really stabilized yet. I think we still see that upward and downward movement. And much of the forecast is dependent on that Department of Finance's outlook on the economic and demographic variables. And that has been a consistent theme.

And to your point, I think the behind-the-meter has been more adjustments towards more accuracy, you know, in terms of kind of moving away from simulation data to real data. That, I think, has been some material impact, but I think the economic impact of post COVID and reorganization of the global and national economy, I don't think, has been fully baked into an equilibrium yet.

COMMISSIONER MCALLISTER: I wanted to jump in here, too, just to the sort of interplay on the demand side of efficiency and load flexibility. I think part of the --

you know, so Vice Chair Gunda, right on in terms of the structural kind of shifts that are still rippling around, you know, COVID and sector-specific forecasts, right, between commercial and residential. You know, and it is true that some of -- you know, that historically what we relied on for energy efficiency savings have kind of played out in the sense that like lighting technologies, that market is fully transformed basically around LEDs. We see a little bit of a tail still of implementation, but that has been a radical improvement in efficiency across the board. And so we've kind of harvested that piece.

But as we electrify, I think there's a great opportunity to have, you know, the new electric loads in buildings, at least in commercial, and to some extent in transportation actually, too, but in buildings, certainly residential, commercial, to build in a high level of energy efficiency in say heat pumps and other end uses.

But also the modern energy efficiency, and I'll probably sound like a broken record here, but modern energy efficiency needs to include load flexibility integrally; right? And I think that's a lot of what we're working on at the Energy Commission is figuring out how best to do that from the appliance level to the building level, you know, on up to rates and sort of, you know, economic response, you know, whether that's, you know, time-of-use or real-time pricing or something between. So that understanding is also evolving. And that deployment, the development of programs and policies and sort of the deployment of those, is also ongoing.

And so I think there is a fair amount of uncertainty in the load flexibility side, but I'm, you know, I'm definitely a glass half full on that front. I'm definitely kind of optimistic in terms of the belief that we will be able to find and implement solutions that'll move the needle there.

So I want to just, you know, keep waving the flag for energy efficiency in its modern iteration, which is digitized and temporal to a greater extent than ever. And I know Commissioner Houck and Commissioner Baker and others at the PUC are also, you know, really leaning into that.

So more than a question, just a comment, but I do appreciate the sort of additional context on the rates, the average rate forecast and kind of the nuances of those intermediate and out years.

Yeah, Commissioner McAllister, I think, you know, just kind of adding a quick comment on this, I think for our team, as we go into the final adoption here, I think it'll be helpful, Mathew, to look at sector by sector forecast and where the maximum deviation has occurred. Is it the residential, commercial, transportation? I think maybe it's all of it. You know, I think the rates have a direct impact as well on the demand. I think it would be helpful for us to get that.

The other kind of, you know, just a quick comment on thinking through about this question, and I think it goes towards, you know, the load factors. You know, Commissioner McAllister, I think to your point, especially the deviation between the transmission planning and the distribution planning is kind of occurring at that local capacity constraints, you know, and the changes in the load factor at those meter level. And I think so many pieces are evolving at the same time, and having a product that serves those different needs in a composite, robust fashion, I think is, again, a big gratitude to the staff, but there's a lot of stuff that we have to continue to do.

COMMISSIONER MCALLISTER: Yeah, and to that point, I'd love to interact with the utilities directly to think about load factor, you know, really as a representative metric of how optimally the existing network is being utilized. And obviously that's got local contextual nuance, and so there's not a sort of one-size-fits-all, but I think that's what you're saying, Vice Chair. And, you know, maybe there are places in that that are sort of, we know we're going to have to upgrade those, and that's going to be a big investment because they're already loaded or overloaded and need replacement or upgrade sort of ASAP or in the near term, but a lot of the grid is going to have a lot of headroom that flexibility can help us take advantage of. And so a load factor kind of basic approach might, or at least, you know, analysis through that lens might really reveal some tremendous opportunities.

And I would love to have sort of a deeper dive directly with the IOUs at least on that, so maybe we can work with staff to get that rolling.

VICE CHAIR GUNDA: Yeah, thank you, Commissioner. I think I totally agree with you. I think we are, I don't know, probably about half an hour off, maybe a little bit over, which is good. This means a really good discussion.

Heather, would you please advise us on how to move forward here?

MS. RAITT: Yeah, so thank you. I think we should just go ahead on to Nick, and we'll keep addressing the Q&A with the written answers and some of the Q&A questions that come up and are being answered in discussion, so thank you.

VICE CHAIR GUNDA: Thank you. Awesome.

MR. FUGATE: So Heather, good morning, everyone. So I'm Nick Fugate, Lead Analyst overseeing the CEC's Peak and Hourly Demand Forecast, which is the focus of my presentation today. I'll do a brief overview, discuss some of the key components of the forecast and how they've changed, and then I'll conclude with some high-level results.

We can go to the next slide.

So Heidi touched on use cases already, but I'll just add a little bit here. The hourly forecast, of course, informs long-term electricity system and reliability studies, IRP, CAISO's transmission planning process. In the near term, it also informs resource adequacy on the RA slice-of-day framework. There's a benchmark for total system requirements at the -- you know, for monthly peak days in the slice-of-day framework. And CAISO's flexibility resource requirement study examines maximum three-hour monthly ramps, which are taken from the hourly. And then for the IOU planning area specifically, our peak forecast is drawn directly from just the maximum load in the hourly forecast.

Next slide.

So at the highest level, the forecast process, it involves applying hourly profiles to individual components of the annual energy forecasts. So this begins with a base profile intended to reflect normal levels of end-user electricity consumption for every hour over a typical year. This base consumption profile is relatively static over each year of the forecast, and it’s meant to reflect present-day patterns of end-user demand.

And then that consumption profile is scaled to our annual consumption forecast with one caveat. Certain high-growth elements of the forecast are first removed because they exhibit a load pattern characteristically different from the base profile. So these are the things we’ve been calling load modifiers, climate change, vehicle charging, behind-the-meter generation, building electrification, data centers. These all have a unique profile that is distinct from and then layered onto the base profile to create the final hourly forecast. And it’s these load modifiers that cause the system profile to evolve over time.

And then as a final step in our process, we benchmark our forecast to our weather normal estimate of annual peak load for the first year of the forecast. And this involves stretching the consumption profile just a bit to align the maximum hourly forecast of system load with that weather normal peak estimate.

Next slide.

So what has changed from CED 2024? First, I’ll start with something that hasn’t changed. We did not re-estimate our base hourly consumption profiles this cycle. And this was an intentional decision aimed at preserving some stability along this dimension of the forecast. We are applying that base hourly consumption profile to a lower annual adjusted consumption forecast. So if you take load modifiers out of the equation, our consumption forecast is lower than the cycles.

We're benchmarking to a higher overall peak starting point this cycle for the CAISO system. PG&E daily peaks from this last summer have increased over last summer in contrast to a years' long downward trend. Our weather normal peak estimate for SDG&E is down a bit this cycle, but that's mostly due to a bias correction we made to our climate simulation data. We fully refreshed our additional achievable efficiency and fuel substitution scenarios. We do this over two years in alignment with the CPC's potential and goal study. And we updated our data center accounting with the latest utility information. And of course, you've heard about the newly available known loads data set and our corresponding impact analysis.

We're also proposing, we discussed this, but we're proposing to revise our planning and local reliability scenario definitions to reflect the more conservative outlook around building and vehicle electrification, and then also raising the prospect of pulling the known loads impacts into the planning forecast.

Next slide.

So this is a bit of a rehash. I’m sorry, was there a --

VICE CHAIR GUNDA: Yeah. So, Nick, this is Siva. I just wanted to make sure, is there a definition of what a planning forecast means that’s -- I mean, is it -- I mean, I know it’s the most reasonable to occur is kind of one of the things we talk about when we talk about forecast. When we talk about planning forecast, is it about an agreed forecast for a certain purpose or is it, you know, our best reasonable estimate?

MR. FUGATE: Yeah, it’s -- so the planning forecast, I mean, I think it largely aligns with sort of our most reasonable estimate of what system level loads will do going forward. But, you know, the exact definition of it is we develop it within our IEPR proceeding, right, both in terms of the scenario definitions for our load modifiers and then the selection. So that’s sort of the first step.

And then towards the tail end of that forecast when we are deciding what our planning and local reliability definitions will be, that is more about discussions with stakeholders, especially CPUC and CAISO, about what, you know, makes sense to use in the specific studies that the planning forecast will inform, that the local reliability forecast will inform. So that determination is sort of made at the end.

And that's why this cycle has been sort of unusual because we have this now, this new known load information and impacts. And so, you know, we're having these discussions at the very tail end of our process to say, well, what do we want to plan for in these specific use cases?

VICE CHAIR GUNDA: Great. Thank you, Nick.

MR. FUGATE: So I apologize, this slide is a rehash of what Heidi and Mathew have already presented, but I did want to show it just because the scenario names I have listed here are the ones I'm going to be using throughout my slides. So my charts I've labeled, anything that I've labeled as simply planning, this refers to our scenario as we originally defined it with mid-level assumptions across the board, including additional achievable electrification. And in this case, in that original definition, we were not planning to include known loads.

Same thing with local reliability. I'm referring to our original definition, which has higher electrification, lower efficiency, and known loads were proposed to be included in that.

And then these other scenario labels are a little clunky, but hopefully they're very descriptive. I meant them to reflect exactly what is included. So planning, no known, FS2, TE2, for example, is our planning forecast with using Scenario 2 for fuel substitution and transportation electrification rather than Scenario 3. And then known loads are not embedded. Planning with known loads, FS2, TE2, same thing except known loads are embedded. And then local with known loads, FS3, TE3, represents that lower level of electrification in our local reliability scenario.

Next slide.

So I’m going to start with load modifiers to give some context for how things are moving before we get to the overall results. My focus over these next several slides will be on just the peak impact of key modifiers and how they changed from last cycle.

I do want to emphasize that there’s a lot of great work from multiple teams that went into these load modifier projections. That work has been presented in detail over a series of meetings leading up to this one. Heidi laid that out in her presentation. And I encourage anyone who’s interested in that detail to revisit some of those presentations and recordings.

Next slide.

So here I’m showing the level of unadjusted consumption for CAISO at hour 18 on the peak day of each year of the forecast. I’ve restricted it to hour 18. My next several charts will do the same thing but for different load modifiers. But recall, unadjusted consumption isn’t a modifier, it’s the level of consumption once all of the load modifiers are removed from our forecast. So at an annual level, this is mostly comprised of our sector model output which is driven by econ/demo. We then apply a base consumption profile which is meant to reflect the present day behavior of the aggregate load. And that gives us the 8760 profile that we layer the load modifiers onto. And so it’s the peak day hour 18 that I’m pulling these series from.

So here you can see that the unadjusted consumption at the system peak hour is roughly 600 megawatts higher than what we projected last cycle, and that remains pretty consistent through the forecast. So the change here is not any significant changes in the underlying portion of the forecast, but really that higher peak starting point that we’re benchmarking to.

We’ll go to the next slide.

This chart is showing the impacts of our transportation electrification forecast in aggregate. So baseline forecast for light-, medium- and heavy-duty vehicles, as well as additional achievable scenarios for each of those categories, that’s all wrapped up here.

One of the impactful themes here is, which shows through even in the aggregation, is deferred growth. So with the move from AATE to AATE -- sorry, AATE3 to AATE2, we see less growth in the early years of the forecast and more aggressive growth later on. And this is especially prominent in the additional achievable light-duty vehicle forecast as well as the baseline medium- and heavy-duty forecasts. And it's also worth noting that the AATE2 assumes no incremental growth in medium- and heavy-duty vehicles beyond what's embedded in the baseline.

Next slide.

For fuel substitution, if we were comparing Scenario 2 for this cycle to Scenario 2 from last cycle, we would actually see significant increases in impacts driven by codes and standards. The delta that we see here is relative to last cycle and it's largely attributable to the shift from Scenario 3 to Scenario 2 which has significantly more conservative assumptions around the adoption of zero-emission appliances.

Next slide.

In this cycle, we see a notable increase in the magnitude of AAEE impacts in the later part of the forecast, resulting in more downward pressure on load. This is driven mostly by our updated codes and standards analysis. There was an effort this cycle to align scenario definitions across AAEE and AAFS, particularly in terms of the level of certainty required for a particular measure to be considered at each scenario level, which led to the inclusion of more standards. There were also just more appliance standards to model in 2025 than there were in 2023, and we improved our accounting of title 24 standards such that first year impacts continue to accumulate further into the forecast period.

Next slide.

We updated our data center analysis with the latest utility data. Actually that's not true anymore. We just recently received one more update from PG&E. It hasn't been pulled into this analysis yet. It's not clear that that will significantly move the needle. I think it was mentioned earlier, some Category 2 projects will be moving to Category 1, while other applications in Category 2 will be -- have been -- have dropped out. So to some extent, those pressures will offset each other. In any case, the final data center projections will change a bit from what I'm showing here. And the significant increase over the last cycle is attributable in large part to a sizable project that we're now considering in Valley Electric Association's territory.

Next slide.

And here's our known loads impacts. Again, this is new product, which is why there's no scenario for CED

2024. Growth is substantial in the first couple years of the forecast, reaching 4,000 megawatts by 2027, and then quickly leveling off after that.

I do have to present these with that huge caveat that this is our -- this was our initial path to developing these estimates based off of energization dates in the known loads data set as well as our initial assumptions around ramp rates. And we've already received feedback on that from PG&E and we'll be developing a revised version of this assessment.

And then, you also heard, we uncovered some data centers and transmission connected projects that should be removed from the analysis. So we're continuing discussions and soliciting feedback from other IOUs and we'll use this new information to develop a revised set of impacts that will be certainly lower than this.

I do want to make a couple more points on that, so let's go to the next slide.

Okay, so for the known loads, we used the information in the known loads data set to develop estimates of annual energy resulting from these projects as best we can. We then calculate the portion of that energy that exceeds the year-over-year growth in our forecast, so there was a lot of discussion about that already this morning. And then when we talk about known loads being added to the planning or local reliability forecast, it's that incremental portion which gets added to our base unadjusted consumption forecast. So implicitly, well, I guess explicitly, it receives the base consumption profile.

Now, this is an example of what that looks like for the SCE planning area peak day. Known loads will be adding, at least for the summer months, more load in the mid-afternoon than in the morning or evening.

Next slide.

But because it's a single aggregate profile that we're applying to all of the annual energy for known loads, any percent movement in that annual energy is going to translate directly to the peak impacts. I borrowed this slide from Heidi's presentation. This is the one where she's showing the revised version of our annual energy for PG&E known loads. It could look like the December update includes the feedback from PG&E, as well as the removal of duplicative or transmission-connected projects from the data set.

So this is closer to what a revised version might look like for annual energy. And you can see that in 2027, for example, that cumulative energy is roughly half of what the initial estimate was. So I just wanted to point out that this would correspond to roughly a 50 percent reduction in the peak impacts of known loads that I showed on previous slides.

Okay. Next slide.

So that was a lot of individual load modifiers here. I'm showing everything side-by-side so you can see their relative impact. This chart shows the absolute megawatt change of these modifiers from 2025 to 2045. This is for all of CAISO. And we're looking, again, just at September on the peak day restricted to hour 18. And these are taken from our planning forecast with reduced electrification and inclusion of known loads.

Our consumption forecast by itself without the impacts of any of these modifiers grows a considerable amount, about 5,700 megawatts over the forecast period. Climate change, about 1,800 megawatts. Data centers contribute nearly 4,500 megawatts. Known loads contribute slightly more, 4,600. Vehicle electrification is still the largest single category with light-, medium-, and heavy-duty vehicle loads combining for over 8,000 megawatts. Additional achievable fuel substitution accounts for another almost 4,500. PV and storage adoption grows substantially over the forecast period, but their impacts at the peak hour are marginal, combining for about 1,500 megawatts of load reduction. And additional achievable efficiency reduces load by almost 3,700 megawatts. So all combined, it's a net increase of over 24,000 megawatts by

2045.

Next slide.

So with that in mind, let's look at the overall forecast results.

Next slide.

Starting with the planning forecast, I'm showing all the scenarios I've discussed so far, including the planning scenarios originally defined. So before the reduced electrification and known loads, that's the solid blue line. And I was showing the planning scenario from the previous image for comparison. That's the blue dotted line. And you can see that before the reduced electrification, our planning scenarios were quite similar to last cycle, at least through 2035, at which point the increased additional achievable efficiency impacts drive our forecast down.

Then when we reduce electrification, so moving to AAFS2 and AATE2, now we're looking at the orange line that reduced electrification drives down load further, particularly in the early part of the forecast. But remember that transportation electrification is sort of deferred by several years. We saw reduced growth in the near term and increased growth in the latter part of the forecast, so that counteracts the pressure from increased efficiency driving the scenarios closer together as we move further out. And then, of course, adding known loads, which brings us to the red line, adds that significant near-term increase, which remains relatively constant over the forecast period.

We’re starting at a weather normal peak of approximately 46,500 megawatts. With reduced electrification, the annual compound growth rate over the forecast period is about 1.7 percent per year, that’s without known loads, or 2.1 percent per year with known loads.

Next slide.

Here’s a look at our local reliability forecasts. The dashed blue line is last cycle’s forecast. The solid blue line is our original definition from this cycle. And then the orange line is local reliability with reduced electrification. In this case, we’re moving from Scenario 4 for AAFS to -- sorry, Scenario 4 for both AAFS and AATE to Scenario 3. And you can see that the change is not nearly as impactful as moving from Scenario 3 to Scenario 4 like we did in the planning forecast. With reduced electrification impacts and known loads, growth in the local reliability scenario is about 2.4 percent per year.

Next slide.

For reference, here are the actual peak forecast values for each of the three scenarios, the CAISO planning with and without the known loads, and then the local reliability, all with the reduced electrification.

What I want to note here is the timing of the peak hour this still occurs in early September across all scenarios and forecast years, and it still transitions from hour 17 to hour 18. But that transition is happening a little later in the forecast than it did last cycle. There's a couple things going on here. One has to do with our calibration to the annual peak. I mentioned earlier that we have less annual energy in our unadjusted consumption forecast and that we're calibrating to a higher peak. So this stretches our consumption profile, increasing those midday consumption hours a bit more than the net peak hours. This means that it takes longer for PV to push the net peak hour to 18.

Then on top of that, we also have slightly lower PV adoption in the early years of the forecast. Then when known loads are added because they follow that base consumption profile, which peaks in the afternoon, that transition occurs even later.

I'll also note that there's no transition to winter morning peaks in any of these scenarios.

Next slide.

Here's an explicit look at that. The blue solid line is the summer peak from the planning forecast this cycle. We've excluded the known loads just to make it an apples to apples comparison between vintages. The dotted blue line is the summer peak from last cycle's planning forecast. The solid red line is the winter peak from this cycle. And the dotted red line is the winter peak from last cycle.

So you can see that last cycle of the winter peak overtook the summer peak at the very end of the forecast period, right around 2042. And you can see that this cycle with less aggressive building electrification impacts the winter peak still growing at a faster rate, but even by the end of the forecast period, it's about 5,000 megawatts below the summer peak.

Next slide.

I said at the onset of this presentation that the early forecast serves as a benchmark for slice-of-day resource adequacy. This forecast specifically would inform 2027 RA obligations, so I'm showing here the change in the planning forecast across all hours of the monthly peak day in year 2027 between this cycle and last, specifically the planning forecast without known loads but with reduced electrification. So in this heat map, positive values indicate that the forecast has increased in that hour relative to last cycle's projection, and negative values indicate that it has decreased. You can see for loads occurring around the annual peak, we're actually in a very similar spot. Not a lot of movement there.

Remember that our annual unadjusted consumption forecast is down this cycle, so that net loss in annual energy is absorbed by the lower load hours, which is why you see reductions on the order of about 2,000 megawatts in the early morning and late evening hours.

Next slide.

And here's that same chart, but this time I've added the known loads to the planning forecast. You can see now that hours that are close to the annual peak are significantly higher by roughly 4,600 megawatts, and the lower load hours see much less of a reduction, and in some cases even a slight increase in load, so this chart exaggerates the impact that known loads would likely have after we've incorporated revised estimates, as I've discussed. But I still wanted to show this chart, since taken together with the chart on the previous slide, it serves as a bookend for where these peak impacts will fall if known loads are ultimately included in the planning forecast.

Next slide.

I have a few charts now showing our non-coincident peak forecast for individual IOU planning areas, starting with PG&E. We have planning and local reliability on the same chart this time. And in an effort to keep things tidy, I've excluded our original definitions for planning and local, so just showing the versions with reduced electrification.

Again, the dashed lines here represent last cycles, vintages. You can see the delta between planning and local reliability is quite wider than it was last year, especially without the inclusion of known loads in the planning forecast. And you can see here we're starting from a higher weather normal peak load than previously forecast, about 20,700 megawatts in 2025. And the compound annual growth rate in the planning forecast is about 2.2 percent without known loads, or 2.6 percent with known loads. The PG&E planning area, on account of all the data center loads, sees the highest growth of any IOU territory.

Next slide.

Similar story for SCE planning area. I'll just note that we're starting from a weather normal peak of about 23,600 megawatts, which is just slightly higher than previously forecast. The compound annual growth rate in the planning forecast is about 1.2 percent without known loads, or 1.5 percent with.

Next slide.

So a few points to make about SDG&E. The weather normal peak is lower than previously forecast. We're starting at 4,236 megawatts. So I mentioned earlier, this is owed in part to a correction we made to the data we used for load simulation in the normalization process. I've discussed this in previous cycles. Our overall method hasn't changed. We're using downscaled climate simulations localized to specific weather stations.

One of the stations we use for SDG&E had lengthy periods of missing data, mostly at night. And we realized this cycle that that was causing -- that was biasing the localized data to be warmer. So we made a correction to that that gave us the cooler set of temperatures for the simulation.

SDG&E's known loads data didn't show the same spike in 2025 energization requests. Their energization dates centered around 2027. So the corresponding load increase happens in 2028, roughly a 200-megawatt single-year increase from concluding known loads.

Comparing planning forecasts between vintages, growth is noticeably lower in the first half of the forecast and much higher in the later years. This still boils down to just decreased fuel substitution, increased efficiency, and deferred transportation load. So SDG&E has a lot of projected vehicle charging for its size, which is assumed to happen largely overnight. In CED 2024, that overnight charging happened earlier in the forecast and competed with load increases from fuel substitution happening at hour 18. The peak did eventually shift to hour 24, but that happened late in the forecast after EV load growth had slowed.

And this cycle's forecast reduced fuel substitution and increased efficiency slowed that peak load growth at hour 18, which causes the transition to an hour 24 peak to happen earlier in year 2039. And because that deferred transportation growth is more aggressive later in the forecast, so is the overall growth and peak.

Speaking of which, the compound annual growth rate in the planning forecast is about 1.9 percent without known loads and 2 percent with.

Next slide.

I think this is the first time I'm showing a peak forecast for Valley Electric Association at one of these workshops. VEA presented at one of our DAWG meetings earlier this year, describing plans for a 1,600-megawatt data center complex under development in their territory. For many cycles, our forecast for VEA has been in the neighborhood of 150 to 170 megawatts. But with the inclusion of this data center load, along with a handful of other known projects, our planning forecast for VEA approaches 900 megawatts by 2035. Almost all of this load exists in Nevada, but we still include it in our forecast just to complete the CAISO outlook.

I do want to note that I'm revising the way that VEA is captured in the hourly results files. So previously, VEA's load had been a single column in the CAISO hourly file. And going forward, I will post a distinct set of forms, identical in format to the other TAC area forms, that are specific to VEA and show the details of these adjustments we're making.

Next slide.

So I'll finish just by reiterating our next steps. We'll be docketing our draft hourly and peak summary forms, hopefully within the next day. These forms will reflect the forecast as I presented it today. Over the next two weeks, we'll be implementing some of the revisions we've discussed. We'll be continuing discussions with utilities, CPUC, and CAISO, as well as considering any public comments and feedback that we receive following today's presentations. And we'll develop and post this final set of results by January 9th, ahead of the January 21st business meeting, where we'll be asking for adoption.

And that's it for my presentation. Happy to take comments from the dais.

VICE CHAIR GUNDA: Yeah, Nick, thank you. I benefit from a lot of our conversations internally. I think there are, and I think we've discussed, there have been some concerns raised, I think, directly to the staff and some of the Commissioner's offices on just kind of the load impact from the known loads.

So I'm thinking more around, you know, for you, especially the presentation, as you think about making those edits, that could be a significant adjustment downward; correct? So I think, you know, if that is a significant piece, I know some of the concerns might be alleviated just from that. Would really want to have the opportunity for the process to play out, so we actually have, you know, another public discussion about this. Obviously, you know, if we work backwards from the business meeting, it will be hard to do another, you know, item that includes all of us.

But I want to really encourage a DAWG meeting you know, I think as soon as the results are done, or even a quasi-DAWG meeting, I don't know. I can see your face changing, but I think, yeah, we need to do some sort of an engagement that's -- you know, what I don't want is we put the data out, so a lot of questions will not be able to answer those in individual meetings, and, you know, we get a lot of feedback at the business meeting. That will be hard for Commissioners to sift through. So it would be really helpful if we could have some sort of a convergence on idea before we get to the business meeting.

I see Heidi coming on screen. She's going to protect, shield you, Nick.

MR. FUGATE: You know, it wouldn't feel like the holiday season if we weren't scrambling to schedule a last minute DAWG meeting on the forecast.

VICE CHAIR GUNDA: Yeah, exactly.

Heidi, what do you think, Heidi? January?

MS. JAVANBAKHT: Yeah. Yeah, I think we could fit one in probably that very first week of January. So I do -- that January timeline is really driven by CAISO's timeline for that. You know, they need our forecast by mid-January to feed in some of their processes. So we really don't have a ton of time in between this workshop and mid-January to make changes, get all of those implemented, and then have another meeting. But we will look for a date, either very end of December or early January, and get something on the calendar.

VICE CHAIR GUNDA: I'm going to take Nick's point of view, and maybe not around Christmas Day, but kind of this kind of thing.

So, yeah, I think, totally, first of all, I know, I think, all humor aside, I know how hard this is on the, specifically, the staff work on forecast. It all comes down to this last few weeks of the year and around the holiday season. I really appreciate, you know, the difficulty of scheduling these meetings. But I think given the number of changes we're going to have, and potential swings of thousands of megawatts a year, I think it's really important to have another touchpoint that's robust.

But if there's another way to do it other than a DAWG meeting, I completely -- you know, it's at your discretion, Heidi, but I think at least having one touchpoint where the stakeholders and the team has a chance to talk would be helpful, holistically. I think it's just Nick's presentation would be special. It's the holiday special.

And I'll pass it to Commissioner McAllister. Thank you. No questions from me.

COMMISSIONER MCALLISTER: Thanks. Just, yeah, I would elevate that conversation. We don't want to be jammed around the business meeting. And maybe there's a way to get the CAISO, the ISO the information it needs, but still allow for some discussion. I hesitate to suggest that we push the adoption out past the January meeting, but anyway, maybe there's some flexibility. We should talk to the ISO about sort of what they need specifically. But I'm sure you're probably already having those conversations, so --

VICE CHAIR GUNDA: Yeah, Commissioner McAllister, I think, just, you know, we have another, the principals meeting on the forecast --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- the Executive Committee. I think we’ll have some. And I think it’s really around what I’m seeing here is the known loads of the known loads once we make the adjustments; right? I think it’s really about how much of that really translates to RA --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- and what rate does that translate to. And I think that’s a decision we need to think through. And I think, you know, the reason I was asking about the planning forecast definition is what I do not want to deviate from is the methodological consistency of having the technical team at the CEC put forth their best reasonable idea of what the forecast is going to look like.

And I think then kind of comes these different variants of the forecast for different purposes. And I think if the question is around the RA, you know, I think we should, you know, we should construct, maybe there’s a way to -- for CAISO to have a variant of the forecast that we don’t expect to change. You know, so we should just think that through, and I think it’ll evolve over the next couple of weeks.

COMMISSIONER MCALLISTER: Yeah. And I mean, obviously, we have to be in a position where we can adopt, where we can agree across the agencies on the set --

VICE CHAIR GUNDA: Yeah.

COMMISSIONER MCALLISTER: -- the forecast set. And so --

VICE CHAIR GUNDA: And I see the concern from CAISO side and the distribution side. You have two infrastructure-related planning activities that really need to be able to have that load in there, so for long-term planning. And I also see the need for resource adequacy to not unreasonably grow, you know, from year to year. That could, especially in a market that's tight, that could really impact the RA prices. So I think it's a delicate balance to think it through.

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: But I think, I just, for the sake of reiterating, what I don't want the technical team to be caught off is to be able to have the opportunity to be able to put their best reasonable estimate of the forecast, regardless of which variant we use for what. So I think that's --

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR GUNDA: -- that's helpful. And Nick --

COMMISSIONER MCALLISTER: Of course.

VICE CHAIR GUNDA: -- we'll make sure we'll buy a few meals for you as you work through this week, you know, and the next week, so thank you.

COMMISSIONER MCALLISTER: We'll send a few Red Bull, a few Red Bulls here and there.

So I did want to just mention, you know, I really appreciate the presentation, particularly some of the visuals, Nick. And the money shot kind of, in some ways, from my perspective, is your slide 15, where you've got the additions and subtractions and sort of, you know, up to something less than 30 gigawatts by (indiscernible), I think it was. And so I really appreciate that. And I'd love to have the next iteration in this conversation as played. I really think that's an important message to, you know, our sophisticated stakeholders about like what's driving all this, and here's how it ends up and some drags off. So I really appreciate that. Would love to just keep, you know, keep fingers on the pulse of how this goes as you get -- as you incorporate the new data from utilities.

And then also on slides 21 and 22, and that's sort of the heat map of the changes, again, just as those evolve and probably become somewhat mitigated with the new information coming in, we talk about sort of presentation and tailoring those a little bit, but we won't want to do that because we don't have much time. But just, you know, let's keep in touch. And I want to make those as communicative as possible for messaging, you know, outwardly once we're comfortable with the results. I think that will be super helpful for me and, I'm sure, my colleagues.

VICE CHAIR GUNDA: Commissioner McAllister, your voice is coming a little light --

COMMISSIONER MCALLISTER: Oh.

VICE CHAIR GUNDA: -- broken. I don't know if that's consistent for others too.

COMMISSIONER MCALLISTER: Oh, sorry about that.

VICE CHAIR GUNDA: We can't hear you, or I can't hear. Maybe it's my tech.

Nick, can you give me a thumbs up?

MR. FUGATE: No, I, well, I can't hear Commissioner McAllister now, but -- and he was coming in low before, but I did take his points about refreshing those charts and using them to communicate the impacts as efficiently as we can.

VICE CHAIR GUNDA: And Commissioner McAllister, maybe we just come back to you. Commissioner Houck came on video too.

Commissioner Houck, anything from you?

COMMISSIONER HOUCK: Can you hear me?

VICE CHAIR GUNDA: Yeah.

COMMISSIONER HOUCK: No, I just really appreciate the presentation. And I'm going to go back through and look at the slides and really want to keep continuing this discussion and looking at how this overlaps with what we're doing, both on the distribution planning and just what we're anticipating for what this means for some of our infrastructure upgrades and data as we're looking at what data we need to make sure we're implementing the right policies. So I just really appreciate the presentation.

VICE CHAIR GUNDA: Thank you, Commissioner Houck.

Commissioner McAllister, do you want to try again?

COMMISSIONER MCALLISTER: That seemed to work. Can you hear me? Okay, great. Yeah, sorry. I've been on so many calls, my primary ear buds have conked down on me.

So, yeah, I was just sort of saying that, you know, as the visuals evolve, I think there's a real opportunity to improve sort of outward communication for all of us, not just me but for our colleagues who -- we're all out there giving sort of the view of, you know, the status quo and, you know, state of the state in terms of where we are with, you know, reliability and evolution of energy demand. And so it will be nice to, like your slides 15 and 21, 22, you know, the heat maps that those -- as those settle, you know, with the new information and you complete the analysis, I'd like to keep in good touch about how those can be most impactful.

VICE CHAIR GUNDA: Thank you, Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. Yeah, thanks a lot.

VICE CHAIR GUNDA: Can I -- Heather, how do we want to do the next steps? I think maybe we just want to go to the public comment, Heather.

MS. RAITT: Yeah, I think we can just go. We've been typing in answers to the written Q&A, so let's go to public comment.

So folks that do want to make public comment, if you can press the raise-hand function to let me know or to let us know. And we'll limit comments to three minutes per person and one person per organization, please. And when we call on you, just unmute your line. And if you could identify yourself and who you're representing, if anybody, and spell your name for the record, that is appreciated.

So let's see. Sorry here. First person is from PG&E, and I'm sorry, I'm not going to be able to pronounce your name. Yu Zhang, go ahead. You need to unmute on your end.

Okay, next, let's just move on to Andrew Mills.

Go ahead, Andrew.

MR. MILLS: Good afternoon. I'm Andrew Mills, A-N-D-R-E-W M-I-L-L-S. I'm the Director of Data Analytics for the California Community Choice Association. And Cal-CCA represents 24 community choice aggregators throughout the state of California.

We really appreciate the time and effort that the Commission puts into developing the demand forecast each year, and really the responsiveness of staff to questions and suggestions. And so I'll just use our comments to highlight the different ways that the IEPR Forecast is used, and the importance of incorporating assumptions that are really consistent with that use.

So the planning forecast is used to set resource adequacy requirements for load serving entities, and to identify resource needs in the integrated resource planning process. And so assumptions in the planning forecast should be consistent with the, really, the systemwide impacts, and account for any coincidence and diversity in loads.

On the other hand, the local reliability forecast is used more in the distribution and transmission planning, where it's appropriate to consider peak non-coincident demand in specific locations. And from our understanding, the known loads represents really engineering estimates of peak non-coincident demand at specific locations and, therefore, it's appropriate for the local reliability scenario. But we're not in support of including the known loads in the planning scenario. Putting known loads into the planning scenario can really increase resource adequacy requirements and costs for load serving entities, even if those loads don't result in a system wide need for more generation resources.

And furthermore, we're just suggesting really a phased approach to incorporating the known loads into the forecast as that data collection process continues to be developed and refined. The recent find that there was as much as 1,500 megawatts of duplication between the known loads and the data centers, the discussion on the interaction between the economic and demographic forecast, and then this question of what rate the backlog can be processed, all really support this idea of doing a phased approach to known loads.

We also see the planning forecast should, in our minds, be an accurate reflection of, really, the expected load in future years. And along those lines, that recent withdrawal of federal policy support for electric vehicles and building electrification warrants the Commission's proposed modification to the EV and fuel switching forecast scenarios for the planning scenario. And we support revisiting these scenarios in future forecast vintages as more data on the effect of these federal policy changes on customer adoption as new technologies becomes available.

And finally, an accurate representation of the data centers in the planning forecast requires increased vetting of the data center applications. And we just encourage some skepticism on applications until greater data center transparency allows for sufficient vetting. The CCAs will continue to work with the CEC, with the Public Utilities Commission, and the investor-owned utilities to develop a process where CCAs can use their local insight to validate information about the status and progress of data center development in their regions.

Thanks.

MS. RAITT: Great. Thank you.

And we'll move on to the next hand up. And I'll also just mention that if you're on the phone and you wanted to make comments, you can press star nine, and that will let us know.

So moving on to Claire Huang. Please go ahead.

MS. HUANG: Hi. Can you hear me? Okay.

VICE CHAIR GUNDA: Yes. Yes.

MS. HUANG: All right, great. Yeah. Hi, everyone. Good afternoon. Claire Huang on behalf of Ava Community Energy. We are a community choice aggregator that serves Alameda County and Stockton and Lathrop (phonetic), soon to expand to unincorporated San Joaquin County.

I just wanted to make a couple of comments on the data center forecast, as well as the known loads on data centers, sort of echoing what Andrew Mills just said, but we want to be able to accurately reflect data center load growth within PG&E service territory and specific to Ava service territory, but wanted to flag that we lack ways to verify the certainty of the data center applications. And we look forward to working with the CEC, as well as the PUC, working through those barriers.

On the known loads forecast, echoing comments from Vice Chair Gunda and Commissioner McAllister, that the forecast seems high and we need to consider really what’s realistic to energize within one year. And we also are in support of either excluding the known loads from the planning forecast or including a lower forecast or a forecast with a longer ramp.

And I had a question in the Q&A about feedback on an updated forecast based off of the adjustments to the known load and the data center forecasts. And I’m hearing that there will be a DAWG meeting scheduled for January, so I’m in support of that as well.

Thank you.

VICE CHAIR GUNDA: Heather, you're muted.

COMMISSIONER MCALLISTER: I think you're muted, Heather.

MS. RAITT: Sorry. Okay. Thanks, Claire.

Next is Josh Harmon. Go ahead.

MR. HARMON: Josh Harmon, PG&E. Just wanted to say that we really appreciate all the engagement and the communication from the CEC, from Heidi, from Nick, throughout this whole year. I know that we all know how complicated this process is. And we have a side chat going with our entire Forecasting Team right now. Everyone's been trying to dig through the same issues that you all have been trying to dig through, especially around data centers, around known loads. And we really look forward to being able to have these candid conversations with all the stakeholders here. So looking forward to more of it.

And apologies to the Forecasting Team for having to put together a DAWG meeting in January, but we're looking forward to engaging. Thanks.

MS. RAITT: Great. Thanks, Josh.

So just another call for -- if anybody else wanted to make comments, you can press the raise hand, or if you're on the phone, press star nine, and that will let us know. I'll give it another moment, but I am not seeing any more comments, so I think that ends the public comment period.

And I'll turn it back to you, Vice Chair. Thanks.

VICE CHAIR GUNDA: Yeah, Heather, thank you so much. And thank you for all the comments that were just provided. You know, totally really hear the comments and the importance of, you know, making sure these have -- these do not have unintended consequences on a lot of different elements of our planning process. So, yeah, I think there's a lot more work to do. You know, also recognize the data quality and data gaps and how to improve them. So really, thank you for all the comments.

I really want to uplift the staff for their excellent work and hard work this year and continued hard work and their openness to constantly review and revise the methodologies to ensure the highest levels of integrity and credibility in the methodology. So just thank you, team. And again, to take one from Josh, just say, you know, sorry that we'll have to do another DAWG meeting, but I think it will serve us well to get one more shot at the comments before we move forward on this.

And, you know, just all the stakeholders, thanks for your participation throughout the year. I think we say this many times, but want to uplift that the CEC, not just at the forecast, but the processes are only as good as the participation and your input and your time. So thank you so much for all that and, you know, keeping, you know, our time open here to make sure that we make the necessary changes as we move forward into the next 45 days before we adopt the forecast -- or 30 days.

And with that, I will pass it to Commissioner McAllister, and then, Commissioner Houck, if you have any closing comments.

COMMISSIONER MCALLISTER: Thanks, Vice Chair Gunda.

Yeah, the challenge of sort of capturing the last, you know, peak season through the fall and then sort of getting ready to allow the planning to happen for the next peak, it’s just really an all hands on deck cycle. So just want to acknowledge the pressure the staff is under and try not to increase that, but also make sure they have the tools to get a quality outcome that’s up to date. And just noticing that December 31st is the comment deadline, which I think I’ll just apologize for that. Maybe we can be a little flexible. I don’t know.

VICE CHAIR GUNDA: Do we want to do January 1st, Commissioner, or -- I’m just kidding.

COMMISSIONER MCALLISTER: I don’t know what the optimal is, but maybe people want to get this off their plate before the end of the year. Who knows? But I just,

yeah, I want to just --
VICE CHAIR GUNDA: Can we just ask Heather, Commissioner, while you're thinking about that, Heather, could we extend that to the 4th or so?
MS. RAITT: That's certainly your prerogative. I know, you know, we were just trying to be mindful --
COMMISSIONER MCALLISTER: Sooner.
MS. RAITT: -- of trying to get the input before for adoption. But yeah, of course, it's --
COMMISSIONER MCALLISTER: Sooner is better. But, yeah --
MS. RAITT: If that's better?
COMMISSIONER MCALLISTER: -- it's tough over the holidays.
MS. RAITT: Yeah, I totally get that.
VICE CHAIR GUNDA: We'll do two deadlines, the first one and then an opportunity.
COMMISSIONER MCALLISTER: Yeah, we really encourage people even sooner than the 31st just to sort of --
VICE CHAIR GUNDA: Yeah.
COMMISSIONER MCALLISTER: -- help us, you know, help staff get everything incorporated. But I just really want to thank, you know, you, Heather, and your team and the staff and the presenters, obviously, with all the

massive like teams behind them, really great update, and, you know, with, I think, a lot of clarity on the uncertainty; right? Because that's a key piece of all this is how the uncertainty propagates and how we try to minimize it, but also just the character of it. So really appreciate staff and our colleagues at the PUC. And just thank you so much for being with us and helping make sure we have that shared DNA and understanding that helps cross-agency planning.

And then thanks, Vice Chair Gunda, for all your leadership on the forecasts throughout the year. Just really appreciate you.

And then finally, just I think we had a peak of mid-200s in terms of attendance today, which is great. And a lot of thoughtful stakeholders who we really appreciate when you chime in. And as Vice Chair said, that's really kind of the materia prima of many of our processes, including the forecast. So thanks a lot. And particularly our utilities and CCAs, just their engagement is critical to getting the right information.

So anyway, I'll end there and pass the mic to Commissioner Houck.

COMMISSIONER HOUCK: Thank you. No, I just want to also join in and thank the staff for all of their work. This is really critical work. And there's so many missing pieces and a lot of really complex, difficult information to work through. And so really appreciate all of the work you've done, the workshops that the CEC has put on, Heather's team, and the partnership that we have with the CEC, with you, Vice Chair Gunda and Commissioner McAllister and all of your colleagues on the Commission. And appreciate the opportunity to hear firsthand from your staff on the information and to continue these discussions. So thanks for including us.

VICE CHAIR GUNDA: Thank you, Commissioner Houck.

And I think, Heather, just to kind of put a pin on the agreement, I think we'll just leave it at 31st and welcome people to provide comments. I think, you know, just encouraging everybody to provide comments as early as they're able to.

Yeah, thank you all.

Heather, if you have any closing comments, otherwise we are adjourned.

(The workshop adjourned at 12:11 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 24th day of February, 2026.

Elise Hicks

ELISE HICKS, IAPRT CERT**2176

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

Martha L. Nelson

MARTHA L. NELSON, CERT**367

February 24, 2026