STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

2022 Integrated Energy Policy)
Report Update) Docket No. 22-IEPR-03
(2022 IEPR Update))
_____________________________)RE: Demand Forecast

IEPR COMMISSIONER WORKSHOP ON UPDATES TO

CALIFORNIA ENERGY DEMAND 2022-2035 FORECAST: PART 2

REMOTE ACCESS VIA ZOOM

FRIDAY, DECEMBER 16, 2022

1:00 P.M.

Reported by:
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P R O C E D I N G S

1:00 p.m.

FRIDAY, DECEMBER 16, 2022

MS. RAITT: Good afternoon and happy Friday, everybody. Welcome to this Commissioner Workshop on Updates to the California Energy Demand 2022-2035 Forecast. This is part two. It's a continuation of the discussion of the forecast that we started on December 7th.

I'm Heather Raitt, the Director for the Integrated Energy Policy Report. I'll just make a few logistical announcements before we get into the substance today.

Next slide, please.

This is a remote-only workshop. And to follow along, the meeting schedule and presentations are posted on the Energy Commission's IEPR webpage. Please note that the workshop is being recorded, and so we'll post a recording shortly after the meeting, and we'll also have a written transcript available in a few weeks.

We welcome participation in this workshop, and so the Q&A function on Zoom is open, and folks are welcome to type in questions. And we'll be taking a few questions for a few minutes after the presentations.

And alternatively, we also have a public comment period at the end of the day, and at that point we'll be opening up the lines if you raise your hand -- virtually raise your hand. And we allow three minutes per comment and one person per organization, please.

And then we also have written comments, which are due on December 30th. We welcome any written comments. And also just today we extended the written comment period from the December 7th workshop to also be December 30th. So get your written comments in by December 30th. That would be great.

And with that, I’ll turn it over to Vice Chair Gunda, who is the Lead for the 2022 update.

Thank you.

VICE CHAIR GUNDA: Thanks, Heather. And welcome, everybody, for the second part of the forecast.

And I just wanted to start by acknowledging the Commissioners who are here in attendance. Commissioner Monahan is here, and Commissioner McAllister. I see him, as well, attending today.

As always, it's important to note a big thanks to Heather, Denise, Stephanie, and the whole IEPR Team for all the incredible work they do in keeping us moving in these workshops, and also the report-writing.

I also want to acknowledge Alicia Gutierrez, David Erne for their leadership at the division level, and then today's presenters, Heidi Javanbakht, Quentin Gee, Alex and Kelvin, as well as Nick Fugate, who is foundational and extremely important for his leadership and mentoring of new staff members, and also leading as a chief forecaster. SCE's contribution, you know, to correct some inconsistencies in their Q4 data this fall and sending us updated data. Thank you for your collaboration.

CAISO for providing their analyses of the Flex Alert response during the September heat event, which is really important to construct the consumption in the forecasts versus what we actually see as the load on the CAISO system.

And JASC members, the Joint Agency Steering Committee members, CPUC, CAISO, and CARB for their invaluable feedback and collaboration on the forecast, you know, process along the entire year, and the changes they propose, and the changes they work with us together on.

So a big thanks to everybody.

I want to just spend a minute on continuing to elevate/socialize the important foundational role that the forecast plays, and then also some of the opportunities and requirements as we move forward.

As we all know, you know, CEC has, you know, four foundational elements that we work on. You know, CEC is the data depository for the state on energy. You know, we are the preferred clean investment vehicle for the state through our R&D programs, through the programs that Commissioner Monahan oversees in transportation -- and by the way, congratulations to her for the incredible plan that we just adopted -- and many other things we do on just providing investments for accelerating clean energy resources in California.

Third, you know, we have regulatory functions, you know, such as Commissioner McAllister, who's the Lead on the Building Codes and Standards and other elements in siting and permitting, you know, that we have some regulatory authority in ensuring, you know, we move the ball on a variety of important elements that support demand growth in California.

And finally, and one of the most important roles that the CEC has, is being this planning and policy agency that's a neutral venue that produces planning assumptions, common planning assumptions for the state, but also provides a venue through IEPR that's generally neutral to have ideation on key policy directives, and then develop recommendations to the legislature and the administration.

So as a part of the demand forecast and the role it's going to continue to play in this, as we move forward into this energy transition and completely accelerate through this energy transition, the forecasting and the analytical work that CEC and especially the Energy

Assessments Division does has a critical role in not just providing the planning assumptions but also constructing scenarios that are necessary to evaluate a multitude of directional pathways that the state could take, you know, the potential issues with them and, you know, the things that we have to navigate along the way, and then developing recommendations.

And that's what you're seeing, the evolution of forecasting, you know, from having a more equilibrium state for the last several years in producing our day-in, day-out IEPR Forecast to more of a scenario analysis that allows for the broader concentrations here. We are evolving it on multiple fronts in terms of looking at policy implementations, looking at, you know, climate change impacts, electrification impacts, and a variety of things.

So I am incredibly proud of the team we have, their intellect, their commitment to the work they do, and the integrity with which they work. And we can always improve as an agency, and that's where the public, the stakeholders play such an important role in helping us make the products better and helping the state move forward together as one big family.

So I will pass it on to Commissioner Monahan. But just, again, a big sense of gratitude to the entire team.

Commissioner Monahan?

COMMISSIONER MONAHAN: Thanks, Vice Chair Gunda.

And I want to say I missed the first chapter of this workshop. I missed the first one, so I'm coming in a little bit midstream.

But I was appreciating actually something you said, Vice Chair Gunda, about "we're moving from an equilibrium to a scenario-based analysis." And it made me think we're actually sort of moving from equilibrium to recognition that our climate system is in a state of disequilibrium, that we're really trying to make sure that our models are more attentive to the changing climate that we're facing, and to some of the threats that are emerging as a result of that, wildfires, higher temperatures, heat domes. So it's just a different world. And I think our team is really working hard to change our modeling to be attentive to the changes in our climate system.

And from a transportation perspective, I would say -- I wouldn't -- I would also say we're in a, I mean, scenario-based is a really good way to put it, where we're learning rapidly what the trajectory of our load is going to be from battery electric vehicles. We haven't yet done an analysis of the hydrogen implications, but that also is part of -- the future of the system is going to be very different from today's.

And I just really want to give a shoutout to the team that has been working on this, including Heidi and Quentin and others, just really trying to model out from a really thoughtful and data-based perspective what's going to happen today, what's going to happen tomorrow, and what's going to happen in the future.

VICE CHAIR GUNDA: Thank you, Commissioner. That's wonderful, and thoughtful comments.

I wanted to see if, Commissioner McAllister, I don't know if you're able to speak.

COMMISSIONER MCALLISTER: Yeah, I’m able to speak.

Looking forward to part B of the dialogue we started last week. And, yeah, just don't have a lot to add, just, you know, I think we all know how critical the forecast, the various components of the forecast, and how unique it is really in the planning world, the energy planning world. California really does this in a way that no other jurisdiction does.

And I think sometimes we get so involved in the details, because it is very detailed work, but, you know, other countries don't really have a way of -- other countries I say, we're a nation state; right? -- don't really have a way of integrating, you know, from top to bottom, the electric grid.

You know, our end use of energy efficiency, load flexibility, those components, those wedges that we put into the forecast, you know, to have a managed forecast really do encompass the wide range of policy instruments that we have at our disposal. And so when we do load flexibility and we enhance that part of the puzzle, that piece of the puzzle, the rest of it can move to accommodate, and that will all be reflected in the forecast.

So I think it's really powerful in that way that we can kind of, over time, just understand all these varied pieces together and, you know, kind of know if we do the work and the detailed work, we keep up on all the pieces and parts, and you know, that's what staff does so well, then we end up with an integrated picture that encompasses all the investments we're making on the -- you know, from all types of generation, all the way down to the appliances behind-the-meter. And that's reflected in how we optimize investment in procurement and in infrastructure. And I think that's just a very powerful approach, and it's kind of -- the sum total of that is very visionary.

And so I just want to thank Vice Chair Gunda for managing that large enterprise so well. And you know, I think we all benefit from it at the Energy Commission and across the state. And it will be even more, I think, critical as the scoping plan become -- you know, that was adopted yesterday. You know, kudos to ARB on that, and Chair Randolph. As that -- sort of the implications of that and the instruments of that permeate the energy sphere, the forecast will be able to march in lockstep.

So I think that's just a really -- it gives me confidence, and should give us all confidence, that this hard work that we do every year, really, but every other year, you know, as a complete enterprise is worth it and brings a lot of value to Californians.

So anyway, that's the context that I -- that's why I always try to, you know, listen into these because I want to just keep sharp on all the different pieces. So thanks for having a platform.

And thanks to Staff for all the great work.

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

Great points by both of you on just the integrated nature of the work and the opportunity for us to really, you know, go through the transition and elevate the necessary analysis for policymaking.

So with that, I will like to call on Heidi to begin her presentation.

Thanks, Heidi.

MS. JAVANBAKHT: Thanks, Vice Chair Gunda.

Good afternoon, Commissioners and everyone attending online. Thank you for joining.

I want to start by expressing my gratitude to the IEPR Team, all the Commissioners on the dais, as well as everyone else attending this afternoon for your flexibility, and splitting what was a full-day workshop on the 7th into two half-day workshops, with today being part two.

I also want to echo the thanks to the Forecasting Team for all of their work this year. In particular, thanks to Nick Fugate for his leadership and mentoring of new team members, as well as team members in new roles.

And thanks to Alex Lonsdale and Kelvin Ke for stepping outside their normal roles to fill in some gaps on the team this year.

Next slide, please.

The goal of today's workshop is to present the overall results of the 2022 California Energy Demand Forecast Update and ask for feedback. The team will go over the consumption and sales results, will show electric vehicle charging profiles, and then present the hourly and peak load results.

We had a workshop last week on the 7th that covered the Additional Achievable Transportation Electrification and Fuel Substitution results, and those presentations and the recording are posted on the IEPR website in case anyone missed that.

Next slide.

I wanted to start by providing some background about why the Energy Commission forecasts energy demand.

In 1974, the Warren-Alquist Act established the Energy Commission to respond to the state's unsustainable growth and demand for energy. As part of this act, Public Resources Code 25301(a) requires that the Energy Commission conduct assessments and forecasts of all aspects of energy, industry, supply, production, transportation, delivery and distribution, demand and prices, and that these forecasts occur at least every two years.

The cycle that we have currently is to provide a full update of the forecast every two years in the odd years, and in the even years we do a partial update. We are in 2022, so an even year, and we did a partial update of the forecast this year.

The forecast is developed with input from stakeholders all along the way. Key stakeholders include the California Public Utilities Commission, the Investor Owned Utilities, and the California Independent System Operator, as these stakeholders use the forecast in various proceedings, such as the CPUC's Integrated Resource Plan, and the ISO's Transmission Planning Process.

Next slide.

Last year's forecast deviated from the usual process. The 2021 forecast was adopted in January and did not include the Air Resource Board's proposed policies for transportation electrification, as historically our forecast has only incorporated policies once they are final.

However, there were concerns that many types of system upgrades require a long lead time, so an Interagency Working Group was formed to discuss the development of a new scenario that included the transportation policies. Out of these discussions came the Additional Transportation Electrification scenario, which was adopted in May, along with an agreement amongst leadership at the CPUC, the ISO, and CEC that there is a strong need to deviate from the 2021 forecast and instead use this new ATE scenario for the ISO's 2022-23 Transmission Plan, and for CPUC's Integrated Resource Plan Portfolio for the 2023-24 transmission planning cycle.

In developing the ATE results, the Forecasting Team only pulled together the files needed by the CPUC and the CAISO, and not all products were created. Therefore, throughout our presentations this afternoon, as we compare it to last year's forecast, you'll see comparisons to both the 2021 forecast and the ATE where those values are available.

As you can see on this chart, the ATE was the same as the 2021 mid-mid forecast through 2027, and after that the ATE reflects higher load from transportation electrification through 2035.

Next slide.

The Energy Demand Forecast has a lot of different data and models feeding into it. Inputs include historical electricity and gas consumption, economic and demographic data, energy prices and rates, and energy efficiency and fuel substitution programs and standards. These feed into the models that we have for the residential, commercial, industrial, and agricultural sectors.

In addition, we have the load modifiers in the green boxes, which include the behind-the-meter distributed generation models, additional achievable energy efficiency, and fuel substitution models. And new for this year, we've introduced a new framework for transportation called Additional Achievable Transportation Electrification, or AATE, and not to be confused with the ATE scenario from last year.

Once all of these components are completed, they are rolled up into the overall end-user consumption and sales statewide and by planning area, and then the last step is to produce the hourly and peak forecasts.

Next slide.

The forecast this year is an update to the 2021 Forecast. Routine updates include adding an additional year of historical data, updating projections of economic and demographic data, and updating the electricity rates. We also update the hourly and peak demand forecast every year, and we incorporated data from September's record-breaking heat and peak load event.

The main changes for this year are the bolded bullets. The first is an update to Additional Achievable Fuel Substitution, or AAFS, analyses to layer in the estimated impacts from the Zero-Emission Space and Water Heater Measure in CARB's State Implementation Plan, and this was presented at the workshop on December 7th.

We've also transitioned to an additional achievable framework for transportation, similar to what we use for energy efficiency and fuel substitution, and that was also presented on December 7th. The additional achievable framework for transportation allows for more flexibility and scenario design that better captures the uncertainty in this rapidly changing sector.

And overall, we've transitioned to a simplified forecast framework which reduces the number of permutations of the forecast to focus on the combinations that the utilities, the ISO, and CPUC use for planning.

Next slide, please. (Coughs.) Excuse me.

The old forecast framework was designed to capture a range of possibilities in energy demand and was centered around economic and demographic uncertainty. To create the range of possibilities, the way the different components were combined resulted in some unlikely and un-useful combinations, and so most scenarios were not used.

Over the past few years, decarbonization and electrification strategies have been introducing more uncertainty into the forecast. To focus on capturing the range of possibilities with electrification, we’ve decided to simplify the forecast framework to analyze one set of baseline economic, demographic, and rate assumptions, and then use an additional achievable framework to look at different levels of energy efficiency, fuel substitution, and transportation electrification.

In addition to the change in the underlying framework, we've transitioned to a more descriptive naming convention for the main forecast sets.

Next slide, please.

And this is the forecast framework for 2022. Again, the biggest change is that we've eliminated the low and the high case to focus on the mid baseline forecast for the economic, demographic, and rate scenarios.

Similar to previous years, the mid-case has different additional achievable scenarios added onto it, depending on the use case. We've moved away from the nomenclature of mid-mid and mid-low and refer to these based on their use cases. So the mid-mid is renamed as the Planning Forecast, and the mid-low is renamed as the Local Reliability Scenario.

The Planning Forecast is used for resource adequacy and used in the CPUC's Integrated Resource Plan. The Planning Forecast includes Scenario 3 from AAEE, AAFS, and AATE.

The Local Reliability Scenario has higher load than the Planning Forecast to take a more conservative approach in local planning studies, such as the transmission planning process at the ISO. It includes Scenario 2 for AAEE, which has less energy efficiency than Scenario 3, and Scenario 4 for AAFS which has more electrification than Scenario 3. And it also uses Scenario 3 from AATE.

The Local Reliability Scenario also includes the SIP strategy for zero-emission space and water heating equipment sales after 2030, which is layered on top of AAFS Scenario 4. And all of these additional achievable layers were discussed at the workshop last week.

Next slide.

So more details around these updates to the forecast framework, inputs, assumptions, and modeling methodologies were discussed at the Demand Analysis Working Group meetings, or DAWG meetings, held earlier this year. Presentations from those meetings are posted online, and there's a link at the bottom of this slide.

Next slide.

And here's the timeline for finishing up the forecast. So the Draft IEPR has already been posted. Due to the timing of posting the draft and the timing of completing the forecast, the forecast results are not in that draft, but they'll be added to the final version posted in February.

The draft results were docketed earlier this week. And comments, as Heather mentioned, comments for the December 7th workshop and today's workshop are due on December 30th, and we'll be finalizing the results based on those comments, as well as comments received today. And we will present those results for adoption at the January 25th business meeting. The Final IEPR will be proposed for adoption at the February business meeting.

Next slide, and this is my last slide.

Before we jump into the 2022 Forecast results, I wanted to give a teaser for the 2023 Forecast.

Building on the modifications to the forecast framework that we made this year, we'll be making some additional updates. We will design scenarios for distributed generation and storage to continue to have something similar to the low, mid and high case that we had before for those technologies. And we also want to think through consistency between scenario designs and pairing scenario combinations that make sense.

Excuse me. Itchy throat.

For example, it may make sense to pair high adoption of fuel substitution with high adoption of solar and storage for some scenarios.

We are also very excited to have several new models under development. The first is an update to the residential sector end-use model, which, among other things, will incorporate the most recent residential appliance saturation study data. We are working with NREL to adapt their dGen model for California, and that will be an update to forecasting all of the distributed generation technologies and would improve our methodology for battery storage adoption. And the Transportation Team is working on updating the travel demand models that forecast vehicle miles traveled.

Lastly, we have a couple notable methodology updates.

We are working to procure behind-the-meter PV data, which we'll use to update the PV hourly generation shapes. We have a contractor reviewing how we currently account for climate change in the forecast, and they will make recommendations on how to improve those methods, and how to leverage some of the new data and tools that are available.

With that, I will hand it over to Alex Lonsdale. Alex is a supervisor in the Demand Forecasting Unit, and he will present the consumption and sales results.

MR. LONSDALE: Thanks, Heidi.

Good afternoon Commissioners, stakeholders, and members of the public. Today, I'll be providing an overview of our 2022 California Energy Demand, Electricity, and Consumption Sales Forecasts.

Next slide.

Before reviewing electricity forecasts, I'd like to briefly review our new forecast framework. In addition, I'll provide details regarding the forecast products that will be docketed as part of our demand forecast.

Next slide.

As Heidi mentioned, for the 2022 IEPR Demand Forecast, we've refined our framework. Specifically, we eliminated the low and high baseline forecasts. Let's take a closer look at the following table.

The first row describes our baseline forecast. This is the building block in which we develop our managed forecasts. Baseline forecasts do not include impacts from AATE, AAEE, and AAFS since these are components that differentiate a baseline sales projection to a managed forecast.

Row two describes our Planning Forecasts which incorporates our mid-case scenario impacts from AATE, AAEE, and AAFS. You'll note that we use colors to provide insight into our old forecast naming convention. The old forecast naming convention would be a mid-mid forecast, since we're using mid baseline assumptions and mid-additional achievable scenarios. As noted in the use case column, this managed forecast is intended to serve planning studies.

Finally, we move to row three of the table, the Local Reliability Scenario. In this case, the old forecast naming convention would be mid-low managed forecast. In other words, the mid baseline assumptions are accompanied by lower additional achievable energy efficiency savings and amplified impacts from fuel substitution. This forecast may serve local planning studies.

Next slide.

Next, I'd like to briefly touch base on our 2022 California Energy Demand Forecast products.

For the 2022 forecast, we refined our annual baseline demand forms to include the following data: annual electricity consumption sales forecast by planning area and sector; total energy to serve load by planning area; historic and extreme temperature peak demand for 1-in-2, 1-in-5, 1-in-10, and 1-in-20 extreme temperature probabilities; economic and demographic assumptions by planning area; and, finally, electricity rates by planning area. It's important to note that our annual and hourly managed forecast product details remain the same as last year.

Next slide.

Now that we're acclimated to the forecasting framework, we'll take a closer look at changes to our economic and demographic forecasts.

Next slide.

Here we can see the average annual percent growth in economic and demographic drivers from the time period of 2021 to 2035. In the first column of the table, we have the economic and demographic driver. In the second column, we have the average annual percent growth from the 2021 forecast. And in the third column, we have the average annual percent growth for this year's forecast.

The objective of showing you slight differences is to highlight how many of our key forecast drivers have not changed substantially relative to our previous forecasts. Detailed projections of several of these economic and demographic drivers listed in this table were presented at DAWG in September this year. I encourage folks to review those graphs.

You'll note that the gross state product and number of households have slightly higher average annual growth rates, whereas the per capita personal income is down by about 0.1 percentage points.

Next slide.

Here we present the statewide average electricity rates. In the y-axis of the graph, we have cents per kilowatt hours in 2021 dollars. In the x-axis, we have two categorical variables. That includes calendar years spanning from 2021 to 2035 and the sector, agriculture, commercial, industrial, and residential. The light blue line is last year's statewide average electricity rate projections. The dark blue line is this year's projections.

Note that rates are calculated using updated revenue requirement projections and the sales forecast from the previous Demand Forecast iteration. These 2022 rates are based on the additional transportation electrification scenario that was adopted in May of 2022.

In general, our forecasted statewide average electricity rates in this year's forecast are lower than 2021, as indicated in the chart. In addition, you'll note that the forecasted growth rates are slightly flatter.

Ultimately, there are higher revenue requirements, which includes impacts from higher natural gas prices and higher grid infrastructure needs to support transportation electrification. However, the increase in revenue requirement is less than the increase in sales, so overall the rates have declined.

More details regarding our rate forecasts for 2022 were provided by our lead rate forecaster, Lynn Marshall, during our DAWG, which took place in September of this year. I encourage folks to review those slides.

Next slide.

This concludes the overview of our economic and demographic projections. Next, we'll look at the 2022 California energy demand baseline consumption results.

Next slide.

Before reviewing key takeaways, I'd like to orient the audience with the format of the line chart presented here, since it's consistent with the next several slides that are key in interpreting our results.

On the y-axis, we have electricity consumption presented in terawatt hours, and in the x-axes, we have calendar year, spanning from 1990 to 2035. The gray line indicates historic electricity consumption. The light blue line represents last year's mid electricity consumption forecasts. And the dark blue line is this year's baseline projections.

Ultimately, residential electricity consumption is down in the near-term, relative to last year's forecast. The 2022 mid baseline average annual growth rate is 0.3 percentage points higher than the 2021 Forecast, resulting in some long-term gains in forecasted electricity consumption. Changes to forecasted consumption is a product of the following: calibration to 2021 quarterly fuel and energy reporting data; revised transportation electricity demand forecast for this year; as well as slight changes to the economic and demographic drivers, including electricity rates.

Next slide.

Next, we have the statewide commercial electricity consumption. Overall, forecasted electricity consumption is higher than the 2021 baseline projections. The average annual growth rate remains relatively unchanged. Increased annual consumption can be attributed to calibration with the 2021 quarterly fuel and energy report consumption data.

Next slide.

Next, we have the industrial sector electricity consumption projections. Our electricity consumption trend remains unchanged from our 2021 mid baseline forecast.

However, the forecasted consumption values are calibrated to our 2021 Quarterly Fuel and Energy Report data, as indicated in the graph. The 2022 industrial electricity consumption forecast values are roughly 2.3 percentage points greater than the 2021 consumption forecast.

Next slide.

Here are the statewide agriculture and water pumping electricity consumption results. The 2022 agriculture and water pumping forecast is slightly lower than the 2021 mid baseline projections. The annual average growth rate is approximately 0.2 percentage points higher in this year's forecast. You'll note that there's a slight uptick in the consumption between calendar years 2021 and 2022 this year. This is a product of our pumping forecast.

Next slide.

Now that we looked at each sector's contribution to consumption, we can review the statewide electricity consumption results, the aggregate of the last few slides.

Higher electricity consumption is attributed to differences in each respective electricity sector, including transportation. The difference in average annual growth rates between this year's forecast and last year's forecast is approximately 0.1 percentage points.

Next slide.

Next, we'll take a look at the electricity consumption by sector, noting that the commercial, residential, and industrial sectors contribute the most to electricity consumption in California. For 2022, the share of electricity consumption by sector remains relatively constant. However, commercial electricity consumption does grow from about 35 percent in 2021 to roughly 40 percent in 2035, for about a 5 percent gain throughout the forecast.

Next slide.

Now that we've reviewed our electricity consumption projections, we'll review our self-generation forecast and electricity sales projections.

Next slide.

The following table shows the total electricity generated from self-generation resources, including solar PV. You'll note that many of our planning area growth rates are consistent with last year. This is a result of our modeling approach during the update cycle, which entailed calibration to historic self-generation capacity data that we collect through form 1304(b). Next year, during our full IEPR cycle, we'll be taking a more rigorous approach to our self-generation forecast by incorporating new modeling tools.

Next slide.

In addition to our average annual growth rates for self-generation, the total forecasted electricity generated is very similar to last year's forecast.

Next slide.

Here are the statewide electricity forecasted sales projections. The objective of the following slide is to highlight the magnitude of impact that self-generation has on our forecasted electricity sales, hence why our self-generation values are reported as negative in this graph.

Without self-generation, our forecasted sales in 2035 would be 68 terawatt hours, or about 23 percent higher than what's currently projected this year. In 2035, the statewide sales are up by about four percent relative to last year's sales projections.

Next slide.

Here are the statewide electricity forecasted managed sales projections. Again, in the y-axis, we have terawatt hours. In the x-axis we have years, spanning from calendar year 2022 to 2035. The gray line in this chart is last year's mid-mid managed sales projections. The light blue line is this year's mid-mid or Planning Forecast managed sales projections. The dark blue line is the Local Reliability projections, or mid-low managed sales projections. Note that the addition of Additional Achievable Transportation Electrification to our managed forecast framework results in increased electricity sales from transportation relative to baseline sales.

In 2035, the Local Reliability and planning managed sales projections reached 331 and 300 terawatt hours, respectively. To put things in perspective, the Local Reliability managed sales projections, the dark blue line, is 24 percent higher than the mid-mid managed sales projections, the gray line, in 2035.

Next slide.

Next, I'd like to provide more details in regards to managed sales projections and how our additional achievable load modifiers impact these projections.

The first chart on the left is specific to the Local Reliability Forecast. You'll note that the AAEE values, the dark blue portion of this stacked bar Chart, is negative since this measure reduces electricity sales.

The next portion of the stacked bar chart shows the incremental impact of AATE, Additional Achievable Transportation Electrification. As shown in the framework, we're using AATE Scenario 3 in both managed cases this year.

Next, the light blue portion of this chart shows the impact of additional achievable fuel substitution. In this case, we're using AAFS Scenario 4, which includes the impacts of CARB’s State Implementation Plan for space and water heaters.

Finally, the gold line cutting through the chart shows how the stacking of these load modifiers impacts sales. In early forecast years, you'll note that the energy efficiency impacts are greater than transportation, electrification, and fuel substitution, thus, the net AA impact is negative. However, in later forecast years, by 2028 you'll note that the fuel substitution and transportation impacts outweigh energy efficiency, thus net AA impacts become positive, increasing sales.

You'll note that the net AA impacts in the Local Reliability Forecast reach about 41 terawatt hours in 2035. That's about 14 percent of total baseline electricity sales, or roughly 60 percent of the energy generated from self-generation resources.

Next, we'll take a closer look on the chart on the right, the Planning Forecast. You'll note that the fuel substitution impacts are substantially lower since we're not considering the CARB State Implementation Plan for space and water heaters.

You'll also note that the energy efficiency impacts are greater. By 2035, the energy efficiency impacts are almost double that of the impacts in the Local Reliability Forecast. Ultimately, the net AA impacts are substantially lower in the Planning Forecast. It's important to note that the Planning Forecast’s net AA impacts are about 9.3 terawatt hours in 2035.

Next slide.

Next, I would like to touch base on the magnitude of impact that transportation has on our forecasted managed sales.

The following bar chart compares the 2022 Planning Forecast managed sales, the dark blue portion of the chart, to the incremental impacts of transportation electrification. I'd like to clarify, the gold portion of this bar chart includes the baseline transportation electricity impacts, as well as AATE Scenario 3, relative to the electricity consumption in calendar year 2021. Essentially, this is showing you the growth that transportation electrification has throughout the forecast, and its ultimate impact on managed sales.

By 2035, the forecasted incremental impact of transportation electrification is about 56 and a half terawatt hours. That's almost 19 percent of our managed sales in 2035.

Next slide.

And finally, we're going to look at sales projections for each of the planning areas.

I'm going to take a minute to just describe each line in this chart as it's consistent with the next several slides. The dark blue line is our Local Reliability managed sales projections. The standard blue, or more electric blue, is the Planning Forecast managed sales projections. The orange line is the AATE managed sales projections that were adopted in May of 2022. The gold line is last year's mid-mid managed sales projection. And finally, the gray dash line is this year's baseline sales.

In the near term, you'll note that the 2022 managed sales forecasts are less than baseline sales, which means the energy efficiency impacts are greater than fuel substitution and transportation electrification impacts. By 2031, however, the managed sales forecasts are past baseline. Again, that means that transportation electrification and fuel substitution load modifiers are greater than the impacts of energy efficiency.

Next slide.

And here we'll take a look at the sales projections for the SCE planning area. You'll note that the 2021 managed sales projections are about 1.2 percentage points greater than this year's baseline projections from calendar year 2022 to 2025. The lower baseline sales in the 2022 forecast relative to last year's managed sales projections is a product of calibration to the 2021 quarterly Fuel and Energy Report electricity sales data. It's important to note that the long-term trends in the

2022 managed sales forecast are consistent with our statewide projections, where you'll note that the managed sales projections for both the Local Reliability and Planning Forecasts surpass the baseline by 2033.

Next slide.

Here are the SDG&E sales forecast results. I'd like to note that the first bullet point refers to an average percent difference. The average percent difference between the 2022 Planning Forecast and 2021 mid-mid sales projections is about 12 percent. However, the percent difference between these two projections in 2035 is 24 percent. Increased difference between these projections can be attributed to increased baseline sales projections, as well as Additional Achievable Transportation Electrification.

Next slide.

Here are the sales projections for the SMUD planning area. You'll note that the AATE line has disappeared. That is because the AATE scenarios were specific to the IOU planning areas.

You'll also note that there are less managed sales relative to the baseline sales for the Planning Forecast throughout the entire forecast period. This is a result of amplified energy efficiency savings relative to transportation electrification and fuel substitution.

Next slide.

And finally, we have the LEDWP planning area results. Like SMUD, the 2022 Planning Forecast managed sales are lower than the baseline sales, except for calendar year 2035. Again, this has to do with the relationship between the three Additional Achievable Load Modifiers: energy efficiency, fuel substitution, and transportation electrification. I would note, though, that the Local Reliability managed sales projections surpass baseline by calendar year 2030.

Next slide.

And finally, I just want to thank all of the staff that have contributed to these forecasts in the Sector Modeling Unit, the Demand Forecasting Unit. We couldn't do it without all of their support. And just really want to thank the village that's behind this forecast and look forward to answering all the questions the dais has.

I've also provided my contact information for those that would like to reach out to me directly.

Thank you.

VICE CHAIR GUNDA: Okay. Thank you Alex and Heidi for those really thorough presentations.

I just want to commend the Division and the Forecasting Team on trying to simplify this extremely nuanced work that we do in both the naming conventions, the way they're thinking about the different types of scenario construction moving forward. So just all around, I could see the evolution of the work over the last several years, but I do really want to call out Heidi, to you, and Nick. And I know Cary Garcia had input in kind of the reimagining the demand scenarios moving forward. So just a really wonderful job.

And Alex, I've kind of watched you kind of grow into this role. Just incredibly grateful and proud of the work you're doing.

So great. Awesome.

So let me kind of pull up a few questions that maybe -- Lynn maybe could jump in here. I'll start off with slide number seven on the deck from -- specifically looking at the rates.

So Lynn, if you could just help inform this.

So the normal kind of outdated conversation is that the rates are going to grow a lot moving forward. We had upward pressure on rates, and then we're working on a lot of stuff. And this is obviously for me at least counterintuitive. While it's counterintuitive, I also see the benefit of having lower rates, meaning higher consumption, which means we're planning for a more conservative situation. All that is good.

But just wanted to understand how we come here to this, and then what any feedback from PUC colleagues has been?

MS. MARSHALL: Yeah. Okay.

So first of all, so this graph only shows rates starting in 2021. So we're already starting from an extremely historically high place. So just between 2020 and 2022, the nominal rates -- these are real rates, the inflation adjustment is quite large these days -- the nominal residential rates increase 20 percent in two years. So this 2021 value you're looking at, that's really high. And in part -- part of that's driven by growth and distribution investment, wildfire mitigation, et cetera.

The other contributing factor, 2021 and 2022, are really high energy prices, in part driven by high natural gas prices driving high wholesale, a tight capacity market.

Okay, so our Gas Team did an updated Natural Gas Price Outlook and they, like EIA and others, are forecasting that in 2023 we would start to see those natural gas prices decline. That leads to a decline in the energy prices. So at the very beginning of this, in 2023 and 2024, that decline in procurement costs is taking us back down, procurement rates, back closer to where they were just a few years ago.

Now, going forward, as we get out past 2025, as we add the additional ATE, that's really what's driving the long run rate forecast down. So we did add additional revenue requirements needed to support the investment, to support more transportation charging infrastructure, other distribution infrastructure. I will say those are very high-level estimates based on historic marginal cost trends. We don't yet have the grid-planning studies, engineering studies that we need to really quantify what that increase in investment will be needed to support electrification.

But that said, the assumptions that we are using, even accounting for that additional investment, the growth in transportation electrification more than offsets the increase in costs to support that growth. And the reason for that, particularly for the IOUs, because there are so many costs embedded in volumetric rates, really have nothing to do with the marginal cost of service; right? So when you have more electrification sales that kind of peanut butters those higher costs across more kilowatt hours, and it lowers the average rate.

So in the short term, to summarize, in the short term we're projecting lower procurement costs that are mitigating the growth. And in real terms, what we have between ‘22 and ‘23 is a leveling off of rates, of nominal rates, not a decrease. But then in the long run, growth in transportation electrification really slows the rate of increase so that real rates are staying relatively constant, or only increasing slightly.

Now, I've gotten -- and I discussed it at the inputs and assumptions workshop last year -- people look at the CPUC staff's SB695 report and say, “Well, that's talking about these big rate increases.” And yeah. And as I said, as of 2022, you know, we've had 20 percent in the last couple of years.

But what they do in that report, and I think it's very important that they do this, is that they assume that the IOUs will get every dollar that they have requested in their rate case applications; right? And I think it's important that the legislature and others see that this was what rates look like if all of these applications are approved. But of course, and the IOUs will be the first to say this, we never get everything we ask for, you know? They might ask for 15 percent, then they get, you know, five-and-a-half.

So, for example, the PG&E general rate case application, which is quite a significant request, I'm assuming a six-and-a-half percent revenue requirement increase, which is a little more, it's like a percentage more than what Edison was approved.

So that's the other big difference between those two staff products. They just serve very different purposes.

VICE CHAIR GUNDA: Got it.

Thank you, Lynn. That's really, really helpful.

So I think -- not for this IEPR but moving forward, I think it might be helpful if we present it similarly, just a little bit of historical data, so that will become easier to see that kind of raised historical context.

But also I think to what you just explained, I just reminded myself, this is a statewide average so you see different projections, and then you're blending all the utilities here, so that's helpful.

Could you confirm that if we -- that the rates have a negative correlation with demand?

MS. MARSHALL: Yeah, that's generally true. We assume that in our forecast that, yeah, higher rates, lower demand. You know, particularly in our forecast models, the self-generation is particularly sensitive to rates. So we didn't actually rerun our self-gen models this time, but it definitely would predict more behind-the-meter investment if we have a higher rate forecast.

VICE CHAIR GUNDA: Right.

MS. MARSHALL: So yes.

VICE CHAIR GUNDA: Yeah, I think, so that's what

I want to leave there is like I know that the NEM decision was just voted out yesterday. The NEM decision will have a number of implications.

I would really like us to -- I mean, I understand the affordability, the rates are CPUC’s domain and we defer to our colleagues from there. But to the extent that, you know, even in my eyes, which is not really educated in this area, you know, helping translate that a little bit, helping crosswalk, this is what you're seeing from PUC, this is why we do it this way, would really help moving forward.

So I would really request that we have a focused work on a workshop and a public hearing on rates next year as a part of our workshop, as a part of our IEPR. Just wanted to flag that.

MS. MARSHALL: Yeah, in particular in the NEM modeling context --

VICE CHAIR GUNDA: Yeah, exactly.

MS. MARSHALL: -- you know what I mean? Yeah.

I mean, to your point, you know, the sensitivity of, you know, the behind-the-meter, that suddenly puts a lot of pressure on the sales and the consumption. And we just want to make sure that we capture that well.

Great. So I have just one other question. I will pass it on to Commissioner Monahan after that.

Maybe, Lynn, this is again you. You're (indiscernible) where I go to. On the pumping load, statewide ag and water pumping load, you know, I'm just speaking to this from the context of reliability. So, I mean, I remember you educating us on the -- you know, as when we have the drought, you know, you have some loads that drop as they pertain to pumping, and some loads go up because of the groundwater pumping that is required, additional groundwater pumping.

I want to understand why we are seeing a reduction in, you know, in the overall pumping load moving forward, if you could add any context there compared to 2021?

So that's slide number 12, Alex, if we could go to --

MS. MARSHALL: We’ll go to the slide, please.

VICE CHAIR GUNDA: Right there. Yeah.

MS. MARSHALL: Yeah.

VICE CHAIR GUNDA: Like why was there -- I mean, like, I heard, you know, Alex saying that's related to pumping in 2022. But we just kind of go down again and flatline.

Again, two opportunities there for me. One is, what is causing that?

And second, you know, as we think through the investments that we were given as an agency for reliability opportunity, we were hoping to capture some of that, you know, that demand right there, so wanted to understand, you know, the shape there a little bit better.

MS. MARSHALL: So generally for things like the DWR and MWD pumping, we're using a ten-year average to get approximation of normal conditions. But then we do have, for the ag sector, we have a specific Ag Forecast based on conditions in that sector.

And Alex, can you comment anything specifically on the ag sector results? Because that would be causing that slight drop between 2022 and 2023.

MR. LONSDALE: Yes, I can. Our lead ag forecaster, Nahidactually provided context to this ahead of the workshop, so as Nahid noted, the 2021 to 2022 jump is a result of the ten-year average that we're using, historic DWR and MWD electricity consumption. So relative to 2021, the historic average is substantially higher, so you've got an increase in consumption to 2022. That slight decrease from 2022 to 2023 is likely due to groundwater pumping assumptions and stabilizing the amount of electricity consumed from groundwater pumping.

So relative to 2022, we expect some of the groundwater pumping to decline, electricity consumption to decrease and stabilize throughout the rest of the forecast period as those econometric drivers stabilize in these NAICS categories.

VICE CHAIR GUNDA: Great. So Alex, I want to again elevate this as an opportunity for us to think through in the next IEPR.

I think what it is, is that, you know, we are entering this new paradigm of, you know, much more frequent droughts and cyclical droughts where, you know, most of the work we're doing, our ability to capture what's going to occur based on medians is really departing; right? So to the extent that we could think through if there are any opportunities to improve, these elements would be really helpful.

You know, overall it's a small number but it's a mighty number from the opportunity of demand flexibility. So that's kind of where I'm kind of thinking, especially as we think through extraordinary measures for reliability purposes. So that would be really helpful if we could spend some time.

I mean, you guys have done a wonderful job, you know, responding to a lot of questions I had already, so thank you for that.

In the interest of time, I'll pass it to Commissioner Monahan first, and then if we have time again, we'll come back.

Thanks.

COMMISSIONER MONAHAN: Well, I'll be brief, Vice Chair Gunda, because you asked my big question, which is the rates question.

It seemed like, you know, given the en banc that we had earlier this year with the CPUC, and I believe CARB was there as well, that that was the most surprising piece to me was just -- and I was thinking about how it would be good, as you said, to include historical. And I would say it's also good to have the rates in, you know, real and nominal, because people's wages don't -- as we had this massive inflation, it's not like people's wages are increasing to match that. And just that personal impact is a real -- is something we should highlight.

VICE CHAIR GUNDA: Love that recommendation. Yeah. Absolutely.

MR. LONSDALE: Yes, thank you for that feedback, Commissioner Monahan.

VICE CHAIR GUNDA: I'm looking at the timeline here. Questions up to 2:10. We have ten minutes more and then we have questions from the public.

So let me just kind of squeeze in one more piece, if I may, just kind of going into the actual shape towards the end of the total results. I'm just looking at -- which one am I looking at? Yes, slide number 18.

So in this one, Alex, the dark blue line is inclusive; right? So it's inclusive of both the self-gen and the Additional Achievable elements, or no?

MR. LONSDALE: It does include self-gen because we calculate baseline sales, essentially taking consumption and subtracting self-generation impacts, but it doesn't -- baseline sales do not include the Additional Achievable elements.

VICE CHAIR GUNDA: Okay. Got it. Okay, so this is the baseline one. Sorry.

MR. LONSDALE: Yeah.

VICE CHAIR GUNDA: Thank you.

MR. LONSDALE: So that would be like the gray dashed line in those managed sales charts for each of the IOU planning areas.

VICE CHAIR GUNDA: Awesome. Thank you.

And then when you spoke about the slide number 21, that one, I just wanted to see if the 21, right there, so that yellow stacks on the side are already in the blue stacks, or no? They are; right?

MR. LONSDALE: That is correct, yes.

VICE CHAIR GUNDA: Okay. Awesome. Okay.

MR. LONSDALE: Yes.

VICE CHAIR GUNDA: Thank you.

MR. LONSDALE: You're correct.

VICE CHAIR GUNDA: Yeah. And I think I just wanted to make sure, Alex, some of the things that you identified as some takeaways on every slide in terms of the percent changes are extremely helpful. I just want to, you know, ask you to capture them in the report, in the IEPR Report, just as some core takeaways, sector by sector or on the energy side.

So with that, I'll pass it to the Q&A.

Thank you so much, Alex. Wonderful job.

MR. LONSDALE: Thank you, Vice Chair.

MS. JAVANBAKHT: Alright. We've got two questions in the Q&A.

The first one is just asking the difference between the Planning and the Local Reliability Scenarios, so I can give a quick overview of that.

Again, the main difference is in the Additional Achievable scenarios for energy efficiency fuel substitution, which was presented at last week's workshop. So we haven't gone back over that today just for the interest of time.

But at a very high level, the main difference is that the Local Reliability Scenario includes less energy efficiency, more building electrification, so more fuel substitution, and then it also includes the CARB’s SIP measure that's been proposed, which is zero-emission space and water heater sales starting in 2030. And that has, actually, quite a big, large -- quite a large impact on the forecast starting in 2030 compared to the Planning Forecast.

And then the second question I'm going to call on Quentin to answer. And this is about AATE Scenario 3.

Does that scenario make any assumptions about anticipated EV load growth?

MR. GEE: Hi. Yeah. This is Quentin Gee, supervisor of the Transportation Energy Forecasting Unit.

And yes, Heidi, Heidi Sickler, you're correct, or we do anticipate load growth associated with additional electric vehicles.

We discussed the framework and the results of that in last week's IEPR workshop, and I'm happy to send you a link if you want to email me. But basically, AATE Scenario 3 incorporates CARB's Advanced Clean Cars II policy, and does also incorporate the Advanced Clean Fleets policy, which is still in development, but we have some confidence that something like that will appear. So that was part of the advanced -- or excuse me, Additional Achievable Transportation Electrification Scenario 3 framework.

MS. JAVANBAKHT: We've got another question.

How is -- well, this question is probably going to be answered in our next presentation, but Quentin, I'll --

MR. GEE: Yeah. We'll get to that one.

MS. JAVANBAKHT: Yeah, so,

"How is managed charging incorporated into the TE projections? Would midday fleet charging be offset by peak potentially curtailed solar load shifting with hybrid solar battery?"

MR. GEE: Yeah. Well, so maybe I should clarify that we will discuss possibilities with that upcoming. But we do not incorporate those in this IEPR Forecast and Planning Scenario framework. Those are very important, and we anticipate integrating those in in future products.

MS. JAVANBAKHT: And another question on transportation. It's the most popular topic.

"Is it possible to get the actual medium- and heavy-duty vehicle count forecast that was used in the AATE scenario for 2030, and also for the individual PA load forecasts?"

MR. GEE : Yeah. So we do have the charts in the slides that we presented in last week's IEPR Forecast workshop.

If you want more precise numbers, you could email me, and we could come up with sort of the numbers behind that -- not come up with but pull the numbers out of the chart and give them to you.

MS. JAVANBAKHT: And Quentin, is this something that you're hoping to post to the Planning Library eventually?

MR. GEE : Yeah. Yeah, I was.

MS. JAVANBAKHT: I'm just going to give a shoutout to the Planning Library.

MR. GEE : I thought about that for a second and then pulled back. But, yeah, that's true.

Actually, Vice Chair Gunda has been talking about this, I think, on various occasions. And I think, Heidi, you also mentioned this. We are working on the California Planning Library and -- or the Energy Planning Library. And one of the things that we're hoping to get in there is some kind of way for people to sort of get the data directly and kind of explore it and work with it.

We're in the process of developing those kinds of products so that they're usable for the public. But, yeah, that's something that we plan to get in there.

If you want the kind of raw numbers behind the charts, I can also just sort of get those values out to folks, as well, if they want to email me.

MS. JAVANBAKHT: Thanks, Quentin.

And Alex, I think this next question is for you.

"How will CEC be monitoring self-generation trends after April 2023?”

MR. LONSDALE: Well, for self-generation trends, we're going to look to our interconnection data to see how systems are being interconnected by different LSEs. We're going to be continually monitoring that data and updating it to make sure we're keeping our pulse on how systems are -- what size the systems are being adopted in sectors, how large those systems are, and where they're located within California.

MS. JAVANBAKHT: And there are no other questions in the Q&A.

Heather, should I turn it back to you?

VICE CHAIR GUNDA: Hey Heidi, as Heather's coming on, I do want to just request one thing.

So again, first, to not -- or to elevate and say how wonderful the presentation style has evolved in the work that we do. It is extremely complicated in terms of, you know, how many layers are in there and how we account for different things.

I would challenge ourselves as a team to come up with a visual that's animated, or however, that shows how we go stepwise on this, you know, construction of, you know, reconstituting the kind of behind-the-meter things back from sales to develop the consumption, and then how you go from consumption to sector-wide, and then to remove the different load modifiers, sort of add them.

I think it would be really helpful to have a visual so people can track this, especially those coming on into this process, you know, so that will be really helpful if we can do that as a part of next year.

MS. JAVANBAKHT: Yeah, sure. We'll work on that.

MS. RAITT: Great. Heidi, this is Heather. I think we've gotten through all the questions.

MS. JAVANBAKHT: Yeah, I don't see any questions.

MS. RAITT: No more questions. Super.

So then we can now, Quentin, officially move on to your presentation. Quentin Gee from the Energy Commission, go ahead.

MR. GEE: Okay, great.

Apparently my background was showing backwards, but it wasn't showing backwards to me, but I'll take it off. I'm sorry about that.

Hi again. My name is Quentin Gee. I'm the Acting Manager for the Advanced Electrification Analysis Branch in the Energy Assessments Division, and I'm also the Supervisor for the Transportation Energy Forecasting Unit.

Next slide.

I've got some just kind of brief information here. We presented the bulk of our work in last week's IEPR workshop where we showed the sort of the baseline forecast for light-duty vehicles, baseline forecast for medium- and heavy-duty vehicles, and then also discussed the Additional Achievable Transportation Electrification framework and the results from those as well.

From here, in this context, I was hoping to just kind of explore a little bit more on the transportation electricity demand load shapes. So here what we're looking at is the AATE 3, the Additional Achievable Transportation Electrification Scenario 3 results, in the hourly form. And here what we've done is we've grabbed a summer day and sort of showed the load shape there.

We've explored the way in which these load shapes are developed in past workshops and Demand Analysis Working Group sessions. But roughly what happens is we take the annual electricity demand associated with, in this case, say light-duty and medium- and heavy-duty. We have input sort of load shapes that we have from different work products from Lawrence Berkeley National Lab, and also from some data that we have from a few years ago showing light-duty and medium- and heavy-duty charging patterns.

And from there, what we do is we take a look at the time-of-use rates and integrate those across different utility territories and assign a sensitivity factor, or elasticity, that modifies charging demand hourly based on the price of electricity at given times.

And in particular what we would say is, you know, generally you're kind of 4:00 to 9:00 p.m. -- depending on the utility territory you're in -- but 4:00 to 9:00 p.m. tends to be one of the time periods where we're looking at sort of the higher rates. But then outside of those periods is a tremendous opportunity for drivers to save quite a bit of money in terms of the cost for charging.

And so what our model does, and we have, again, we have some work documenting this, and happy to share that if folks are curious to learn more about it, but we basically take this and run it in a pretty sophisticated model that comes out with these charging load shapes. And here what we can see is during those peak periods we have fairly low demand, and then that's made up for periods -- made up by periods in other times of the day.

So this is something that actually goes into the planning products and is really useful in terms of evaluating, you know, what -- how does transportation electrification, how do we expect it to impact the grid in the future?

We've had a lot of questions from that, especially relating to some of the energy topics and issues that came up last summer. But we're looking at anywhere sort of around five-ish or so percent during peak time periods in 2030. Nick Fugate will talk more about that.

One caveat that I would want to point out on this is that this model is based on time-of-use rates that we have from utilities. Utilities only really, you know, present or apply and get the time-of-use rates adopted sort of for about, you know, four to six years or so out. And so we do not have the actual time-of-use rates for 2030.

So we know that utilities are roughly interested in trying to adjust their time-of-use rates to optimize their grid planning and help consumers save more money, but certainly we can't say that these are the time-of-use rates in 2030 and this is exactly what the model would look like.

But it also can be informative. You'll notice there in hour 21, or around 9:00 p.m., that's when a lot of time-of-use rates either go to off-peak or they go to some sort of mid-peak. And our model shows that there can be a little bit of a bump there during that time period. And that could be informative for some time-of-use rate planning.

Next slide.

So the next thing that I wanted to discuss here is the sort of additional opportunities that we want to look at. We do have an order instituting informational proceeding on distributed energy resources, and part of that involves analysis of electric vehicles as distributed energy resources.

And so as I just showed in the slide before, you know, we have time-of-use rates that do impact load shapes and are likely to sort of help consumers save money, and then also keep the grid sort of in a reasonable balance there. But there are some other opportunities. And what we're hoping to do is explore these in a workshop in early 2023.

So some key technologies that we can sort of -- or key opportunities that I would say we'd want to take a look at here are vehicle-to-grid. Vehicle-to-grid is where the driver will actually export energy onto the grid and use that as a potential opportunity to make some money.

There's also vehicle-to-building where someone might sort of view themselves as wanting to take advantage of the battery in their vehicle and run their house off of the battery rather than off of the grid, particularly at times of time-of-use.

And then we also have two other opportunities as well that we want to take a look at.

Managed charging. Managed charging is sort of where you roughly set a kind of, you know, 7:00 a.m. I want to wake up and have a car at 100 percent or maybe 85 percent state-of-charge. Whatever it is you say ahead of time you want. And what happens is that you have an operator or a system or some kind of software that will allow it to kind of optimize and get you the lowest rates by being flexible throughout that sort of eight-hour period while you're asleep and that can allow you to save more money.

And then finally, there's also demand response, where similar to managed charging where you're getting signals, there might be a signal that says, hey, you know, we'll pay you X amount of money to, you know, just sort of drop off your demand for a little while and it can come on later. And if you have it set up to where, you know, it doesn't matter as long as you wake up with a certain amount of battery that you want in your car, it should be good there.

These are things that -- these are technologies and opportunities that we think could have a pretty big role in what the load shapes will look like in the future. But a lot of stuff right now sort of looking at technical potential, but also kind of looking at what are the kinds of policies and programs that might be out there to help with this, and also help the grid at the same time.

So that's the kind of rough-rough take on the load shapes and additional opportunities for where load shapes might be changing in the future for transportation electrification.

I think with that, Nick Fugate has a little bit more to discuss on hourly outside of transportation electrification. So I'll pass it on to Nick Fugate, who is the load shape -- Hourly and Peak Load Shape Analyst.

Nick?

MR. FUGATE: Thank you, Quentin.

Good afternoon. I'm Nick Fugate and I've prepared a presentation here on the draft results of our Hourly and Peak Electricity Demand Forecast for this 2022 IEPR Update.

Before we start, I just also want to offer my thanks to everyone for their time and attention today, especially with the late change to our workshop schedule on Friday afternoon, part two.

So let's go to the next slide.

So the Energy Commission's peak forecasts are used as a direct input to resource reliability and transmission studies. Specific use cases for the Planning and Local Reliability Scenarios that we are presenting today, they're outlined in detail as part of the single forecast set agreement between the CEC, the CPUC, and the CAISO. And this agreement evolves year to year, or can evolve, but it's always memorialized within the forecast chapter of our IEPR report.

I'm going to present today the Peak Forecasts, but I will also be discussing updates to our hourly model as the peak results are derived from our hourly model.

Let's go to the next slide.

I imagine by now I don't need to say too much about the motivation for using an hourly model demand modifiers like PV, storage, EV charging, building electrification now. These can have an impact not just on the rate of peak load growth but also the timing, and the timing of the peak hour and the magnitude of system ramps.

Next slide.

The structure of our Hourly Load Model, abbreviated HLM, it's unchanged from last cycle. We apply a base load profile to our annual consumption forecast.

And here, "consumption" is in quotes because this doesn't represent actual total consumption, but rather utility sales minus pump load plus behind-the-meter PV generation. So what we're trying to model is the portion of load that is responsive to things like weather and economic and demographic drivers.

For the forecast years, we then layer incremental load modifier impacts on top of that base profile. Impacts from climate change, electric vehicle charging, behind-the-meter PV efficiency, and fuel substitution, these are estimated separately as they are expected to alter the shape of the system profile over time.

And then finally, we calibrate the base profile such that the resulting maximum value aligns with our weather normal estimate of peak load in the first year of the forecast.

Let's go to the next slide.

So I won't say a lot about this. Heidi already talked about it. Alex talked about it. Moving to a new forecast framework, so, essentially, the Planning Scenario that we're presenting here is equivalent to the mid-mid scenario that we previously developed, and the Local Reliability Scenarios that we're now calling what we used to refer to as the mid-low scenario. And just to be sort of specific about the use cases, specifically that Local Reliability Scenario is intended for use in CAISO’s TPP and RA local capacity studies.

So as far as updates to the forecast are concerned, we have a new Annual Consumption Forecast, which Alex just spoke to. This is a foundational input to the hourly model.

We also have new Additional Achievable Fuel Substitution impacts feeding into specifically our Local Reliability Scenario. These include the ARB's new State Implementation Plan rules around space and water heating. And again, Ingrid Neumann discussed these during part one of our forecast results workshop last week. And at that same workshop, our Transportation Team presented their updated forecast for electric vehicle adoption and charging.

And, as always, we have one more summer's worth of load data that we have incorporated into our weather normalization peak estimate.

Let's go to the next slide.

So I'm actually going to start with our weather normal peak estimate.

Next slide.

So I don't think I'm breaking any news here when I say that the summer of 2022 had some particularly hot days. CAISO set a new record for peak system load, the previous record having been set in 2006, which I actually remember; that was the year I moved to Sacramento from the Bay Area, and I did not know how I was going to live here in this oppressive heat.

Anyway, I've plotted here an average temperature index for CAISO over the last 30 summers. This index is in a direct input into our model, so we just use it to put some historical context around a particular heat event.

The blue highlighted line is 2022, and you can see that September 6th was the third hottest event in the last 30 years based on this statistic in particular. And I have to caveat that because it takes into account only the single-day temperature. So start looking at temperatures over consecutive days, that ranking might not hold. 2022 starts looking even more extreme.

But examining just the single peak day index in the context of the last 30 years, Staff’s analysis characterized this as a 1-year-in-27 event.

Next slide, please.

So we calibrate our model results to the most recent year of historical load. But peak load is highly sensitive to temperature and our hourly forecast assumes normal or 1-in-2 weather conditions. So it's important that we not calibrate our results to an extreme load event, like what we saw this summer, and instead we need a counterfactual estimate of peak load which takes into account the recently observed load response to temperature but then assumes normal peak weather conditions.

And to illustrate that point, I've plotted daily peak load here against a weighted average temperature statistic for our San Diego Gas and Electric planning area. Here the slope of the lines would give some rough intuition around the load response to temperature in each particular year. And the vertical position of each line can give some insight into absolute peak load growth.

And looking at this chart, you might expect that the weather normal estimate for 2022 would be higher than the 2021 estimate. And when I get to the results of this analysis in a few slides, you'll see that that is the case.

Next slide, please.

So having established that load temperature relationship, we need to assess that relationship under normal peak conditions. And this raises the obvious question of what normal actually means in the context of a changing climate.

Here I've created two density plots showing the distribution of annual peak values for that CAISO temperature index I discussed earlier. The blue plot is based off of the last 30 years of weather history, which is the window we have traditionally used to establish normal conditions. And the orange plot is based on just the latest 20 years.

When we talk about normal conditions, we have in mind that 50th percentile, the point in the distribution where you're equally likely to fall above or below. And you can see that truncating the historical window skews the distribution to the right, leading to slightly higher normal value. For median, the increase in the 95th percentile, or what we call the one-year-in-20 conditions, is more significant, implying that temperatures that used to be highly unlikely are becoming more common.

As an example, Staff took another look at that September 6th heat event from the summer. I mentioned earlier that it ranked as a 1-in-27 occurrence when we looked at it in the context of 30 years. But when we examine it through the lens of just 20 years, the most recent 20-year window, it looks more like a 1-in-14 event.

During the 2021 IEPR cycle, we took some interim steps to account for this warming trend in our normalization analysis, retaining the 30-year window but assigning greater weight to more recent years. And we continue this for the 2022 update.

But looking ahead to the 2023 IEPR, we're expecting to be able to leverage newly available climate modeling results to improve our estimate of normal and extreme weather. Heidi alluded to this in her presentation, but we're currently engaged with Eagle Rock Analytics who are developing some analytical tools for this purpose. And I have to thank our Energy Research and Development Division for their enthusiastic support on this work.

Next slide, please.

So to review our specific process at a high level before I show the results, to normalize peak load we start with hourly system loads from CAISO and we add to that estimated impacts of load reduction events. These could be call programs for voluntary conservation during Flex Alerts, as examples.

These estimates come to us from the IOUs and from CAISO. We do this because dispatchable demand response is considered on the resource side of the balance sheet, and so we don't want to double-count those impacts by embedding them in the forecast.

As far as weather data goes, we have a number of weather stations located across the state that we weight to create a single set of daily statistics for each planning area.

Once we have our counterfactual loads, we select the peak load day for each of the last three summers, and we regress those against weather effects such as maximum and minimum daily temperatures, calendar effects such as days of the week, month, and year. We do this to establish that load response temperature, and then we use the regression models to simulate peak loads using historical weather data from the last 30 years. And it's during this simulation step, as I mentioned previously, that we have been drawing more frequently from recent weather patterns.

And from this resulting set of simulations, we take the maximum values and select the median from those maximums as our normal estimate.

Next slide, please.

So here are the results of this process. On the left side here, the left column for each of the IOU planning areas, we have the recorded peak load on the left. And then we have the counterfactual peak load, that I mentioned, we get by adding the load reduction impacts to the recorded load. Then we are showing the weather normal peak estimate for each planning area. And then for comparison purposes, I've also included the weather normal estimate from last year's cycle, CED 2021.

And you can see for PG&E and SCE, the normal estimate is about one percent lower than last year's, and SDG&E's is almost three percent higher. The method is unchanged, so this is mostly a result of dropping 2019 from the set of historical years used to estimate the regression models. For PG&E and SCE, 2019 was contributing to a slightly greater load response. For SDG&E, 2019 was actually contributing to a slightly lower response. But then also for SDG&E specifically, there appeared to be just an absolute load increase across all temperatures in 2022 relative to 2021.

Next slide, please.

So for the update, most of the load modifiers are consistent with the 2021 Forecast. The notable changes results -- sorry, revolved around fuel substitution and transportation electrification.

Next slide.

I did want to show the relative contribution from each load modifier during the CAISO system peak hour, which is projected to occur in early September. I'm also just happy to have a reason to make a waterfall chart.

So specifically, this is showing the incremental impact in hour 19 from modifiers added over the forecast period, so the impacts in 2035 relative to our 2021 base year, and this is for our Planning Scenario. And here you can see the greatest contributions are coming from electric vehicle charging increasing load by nearly 4,400 megawatts, and then energy efficiency reducing load by over 2,400 megawatts. The net impact from all load modifiers reaches almost 1,900 megawatts.

Next slide.

And here's a similar chart but for the Local Reliability Scenario. And you can see the reduced contribution from efficiency, so roughly 1,000 megawatts less than in the Planning Scenario, and the significantly increased contribution from fuel substitution, so another 3,000 megawatts of AAFS on top of the Planning Scenario. Although space conditioning contributes less to fuel substitution impacts during the summer months, the SIP measures still include a significant amount of water heating impacts.

Next slide.

So here I'm showing the evolution of the CAISO peak day profile over the forecast period, specifically for the Planning Scenario. Behind-the-meter solar continues to slow load growth in the midday hours. The most significant load growth happens in the late evening and early morning driven by electric vehicle charging. The evening ramp becomes quite steep and the afternoon-evening ramp becomes quite long as the -- I'm sorry -- becomes quite long as the initial relatively flat peak period grows to a pronounced peak at hour 19.

Next slide.

For the Local Reliability Scenario, the annual CAISO peak is still projected to occur in September, but I wanted to show that the impact that Additional Achievable Fuel Substitution has on the CAISO winter peak. This is the most extreme day in February, and you can see that fuel substitution measures push load to 50,000 megawatts at 8:00 a.m. And on today's system, that's on par with a very extreme summer peak.

Next slide.

I have a few slides here on electric vehicle charging that will hopefully provide some context for the annual peak results, which I'll show next.

This one is a plot of annual energy for vehicle charging, which compares the forecast update with last year's vintage. The legend shows five scenarios, but the

Planning and Local Reliability Scenario assume the same levels of vehicle charging, and the same is true with the mid-mid and mid-low from last cycle.

In May, however, I mentioned the Commission did adopt that Interim Scenario that assumed increased electric vehicle charging from the ARB plans. This is the ATE scenario here, the Additional Transportation Electrification Scenario, so we'll be making comparisons between the current Planning Scenario and the ATE.

So I wanted to note here that our updated Vehicle Charging Forecast is down relative to the ATE scenario. Our Transportation Forecast Team discussed this at last week's workshop. It's generally due to increased assumptions around fuel economy, reduced VMT, and reduced charging for plug-in hybrid vehicles.

Next slide.

Our Transportation Team also updated TOU rate assumptions, as Quentin mentioned, and these are used to calculate elasticity adjustments to our base charging profiles. Here I'm showing a normalized summer daily charging pattern for PG&E for both this cycle and last. The percentage difference between peak and off-peak rates narrows for this forecast, which has the effect of shifting less load away from the peak window. And to say that another way, more charging happens during the peak window and generally less is happening off-peak.

Next slide.

And this chart shows the combined impact of both of these sets of changes, the reduced annual energy and revised charging profile. There is a similar level of EV charging happening during hours 16 through 20, but the ATE Scenario projected significantly more charging during hour 21. And this was actually enough to push the PG&E system peak from hour 19 to hour 21 in the later years of the ATE Scenario. For this forecast, however, the PG&E system peak remains at hour 19.

Next slide.

So keeping that in mind, let's take a look at the planning area annual peak results.

Next slide.

For PG&E, annual peak load in the Planning Scenario grows at 1.3 percent annually. This is clearly lower than the ATE Scenario from last cycle which has significant growth in the later years of the forecast due to that shift to hour 21.

The Reliability Scenario grows at 1.8 percent annually, and by 2035 the difference between the Planning Scenario and the Local Reliability Scenario is about 1,800 megawatts, much larger than the difference between last cycle's mid-mid and mid-low scenarios.

Because it's important for resource adequacy, I have made a note here that by 2024, the Planning Scenario annual peak is two-tenths of a percent lower than the CED 2021 mid-mid, so not much change there.

Next slide, please.

For the SCE planning area, the peak shift is projected to occur on a later timeline relative to the other IOU planning areas, shifting from hour 16 to 17 in 2026, and then to hour 19 in 2030. Unlike PG&E, the additional electrification load present in hour 21 of the ATE scenario was not enough to shift the peak hour any later than hour 19, so consequently, the CED 2022 Planning Scenario aligns very closely with the ATE from last cycle.

Annual growth is 0.8 and 1.3 percent for the Planning and Local Reliability Scenarios, respectively. By 2035, the difference between the two is nearly 1,800 megawatts. And in 2024, there is almost now -- sorry, almost no difference between the Planning Scenario and the mid-mid from last cycle, just a 0.1 percent increase.

Next slide.

For the SDG&E planning area, you can see the near-term impact at the higher weather normal starting point. This translates to a 1.5 percent increase in the Planning Scenario over the previous mid-mid scenario by 2024.

There was a similar phenomenon in the ATE Scenario for SDG&E, similar to what I discussed with PG&E where the vehicle electrification pushed the peak hour from 19 to 21 in the later years of the forecast. And this actually still happens here in the Planning Scenario, but just at the very end of the forecast, which is why you see that uptick in the last year.

Growth rates are 1.2 percent and 1.8 percent annually for the Planning and Local Reliability Scenarios, and the delta is 2035 -- I'm sorry, the delta in 2035 reaches nearly 400 megawatts.

Next slide.

And finally, here we have the CAISO Coincident System Peak Forecast. Similar to what we saw in the SCE planning area, we’re closely aligned with the previously adopted ATE scenario. In both cases, the peak is expected to shift to hour 19 early in the forecast and remain there throughout. Growth is 1.3 percent and 1.9 percent annually for the Planning and Reliability Scenarios. And the delta between the two reaches is nearly 4,000 megawatts by 2035. And in 2024, there is a small 0.3 percent increase in the Planning Scenario relative to the previous mid-mid.

Next slide.

So this is not a comprehensive list of updates for next year's forecast. I just want to flag a couple new data products we are anticipating that will have implications for our hourly modeling.

First, we're attempting to procure on-site generation data from a large set of metered PV systems. We've discussed our PV generation profiles at past workshops. Our forecast profiles are based on meter generation, but from a relatively small sample of older systems, actually, systems that were installed at a time when it was much more important for the system to be south-facing if it was going to be cost-effective, and that's not really the case anymore. This is anecdotal, but I can look out my window right here and see my neighbor's array of northwest-facing panels.

So this data should allow us to ground-truth our forecast generation profiles. It should also improve our historical reconstitution of hourly consumption, which is important for estimating our hourly model. And it may open up some options for improving our weather normalization process, specifically as it relates to the hourly model. There are some days in areas where cloud or smoke cover may be contributing to daily peak load and, by consequence, reducing behind-the-meter generation.

There is also some evidence that customers with PV are more likely to run their AC systems more on particularly hot days, just because they have the system and feel like that's covering the load. And having actual meter generation will help us explore these types of questions, so looking forward to that.

And then secondly, I touched on this already in another slide but we're excited to begin incorporating a new round of climate modeling results into our forecast. This should be relatively straightforward to update our previous climate change impact analysis, but there are a number of other questions we are interested in answering.

And one of our first priorities will be to leverage the climate data to improve our understanding of normal and extreme weather conditions. And so we're looking forward to discussing our thoughts on this early next year ahead of the 2023 IEPR.

Next slide.

But before we start work on the 2023 IEPR, we have to close out this forecast update, so this involves docketing all of our draft results, which we've already done for the hourly and peak forecasts. You can see all the data that I've presented here today on our IEPR website, specifically under the documents heading of today's meeting page. But we will also try to make as much available early next week as we can, perhaps even some of what was asked for on this at this meeting today already.

Stakeholder comments are due December 30th. And after considering feedback, our plan is to take the final forecast to the January 25th business meeting to request adoption.

I also want to mention that we will be posting documents to the CEC's Planning Library, at least that's the intention, beginning with this forecast.

We're still deliberating a bit internally on the best way to make our forecast detail available. We still plan to produce our standard forms for the time being, but we will also be looking to make load modifier and hourly detail available in a way that's both easy for us to produce and also easy for stakeholders to consume.

And I'll flag right now that the peak file I posted is a little different than what I have posted previously. The file contained just -- the previous file contained just annual and monthly coincident and non-coincident peaks. What I posted this time looks much more -- look more like the data set that I used to develop this presentation. It retains the hourly results file format with all of the load modifier detail. And it has entries, not just for the coincident and non-coincident peak hours but, also, for the full 24-hour peak day profiles. And this is the same with the monthly peaks. So a richer data set that is hopefully more informative.

And I think with that, I'll just thank everyone again for their time and attention today. And I’ll defer to the dais for comments or questions.

VICE CHAIR GUNDA: Thanks, Nick. Thanks for the presentations.

I just wanted to begin by just acknowledging the tremendous work you, particularly, put into this, the time. And this is not easy to pull all the different threads together and be responsible for one of the most important analytical products that the state produces as a whole. And given the importance around energy planning, reliability, the energy transition and equity, this is such a foundational element of everything we do in the state. So I just wanted to both recognize, you know, the hard work you put in, you know, and do it so gracefully and thoughtfully. So thank you, Nick. Thanks for all the work.

I also want to recognize, you know, a couple of Staff that are retiring, you know, Bob McBride from the Transportation Team, as well as Mitch Tian from the Assessments Demand Group. Broadly, so thank you for your contributions over the years and, you know, we'll miss you. And thanks for all the wonderful work.

And I know we also lost a couple of really strong Staff to other agencies, Cary Garcia and Matt Coldwell, for their work that they've done before they moved on to other agencies, so thank you for your work.

So I just wanted to all-around thanks first.

And then kind of going into, Nick, a few questions, and I'll kind of leave the transportation questions to Commissioner Monahan, but I want to just go into a couple of observations/thoughts for us to think through.

If we go to slide number 15 on the presentation you just made, you kind of mentioned, you noted this already and I just wanted to flag this for the broader dais, you know, there’s Commissioner Monahan, but also our Energy Planning Team, I think you made a very important observation about the length of the ramping time that we begin to see here, but also the magnitude of the ramp in the evening hours.

This has, you know, from an energy planning/resource planning, a direct implication to storage, and then the storage duration and load flexibility. So I wanted to just make sure that I tagged this to you, Nick, to work with our supply team on kind of the reliability planning and emphasize this, these specific elements.

On the next slide that you brought up, again, a huge insight. You know, we just hit a 50,000 peak in September this year, which we thought was crazy. And your next slide here shows that we can hit that in February. That is absolutely bonkers. So I just wanted to note that is an important element for us to continue to track.

This goes towards planning for reliability year-long, not just for the summer and the potential dual peaks that we'll see across the year, but also during the days. You know, it's interesting to watch that you will have the peak in February in hour nine or hour eight versus evening. So just important insights for that, so thank you.

Maybe this is kind of one question, if you could expand a little bit on slide number nine, your specific climate considerations? You know, could you talk about the data and how we are using this and how this could inform the broader discussion on reliability as you see right now? So let me kind of state that a little bit more.

Currently, right, I mean we have CPUC planning for resource procurement based on the mid-mid forecast or the Planning Forecast, the 8760. That gives you a certain amount of resources. But, you know, over this last six months we recognized that even in the best-case scenario that CPUC is able to procure, authorize the procurement of those resources to meet the planning standards, and able to deliver that, we still have this incredible amount of needle peaks that we could see.

So I'm just asking from the context on, you know, how do you see this information helping us think about how to plan for the extreme as our analytics continue to improve?

MR. FUGATE: Sorry. Sure. So, yeah, thank you for that question.

You know, certainly -- well, I guess I'll preface this just by saying that, you know, this chart in particular is just sort of illustrative of the problem that we're grappling with right now.

So you know, currently we have tried to capture some of the increased warming in our onein-two estimate of peak load. But certainly, you know, there's clearly, you know, even just looking at the recent historical data set, you know, clearly we are looking at increased likelihood of more extreme temperatures. So even if we have just -- even if we feel like our one-in-two estimate is reasonable, if we are planning, you know, around that one-in-two estimate, we should also be prepared for, you know, increased magnitude of deviations from that one-in-two.

I think, you know, having -- our intention is to, you know, once we have, you know, this rich climate modeling data set, our intention is to leverage that in conjunction with the historical, you know, weather patterns to get a better idea of, you know, what a one-in-two looks like, what a one-in-five looks like, what a one-in-ten could look like and produce, you know, more reliable estimates around those peak factors.

But you know, for the time being, we're working just with the historical data set. We're sort of limited in what we can do. You can only like truncate the historical window so far and then it becomes quite difficult to estimate a distribution based on, you know, less than -- trying to estimate a 1-in-20 with less than 20 data points, it doesn’t necessarily -- you're not going to necessarily have confidence in those estimates too.

So I think having the climate modeling results is going to be a critical addition to our toolkit here.

VICE CHAIR GUNDA: Yeah, so just another follow up on this one. So that's really helpful.

So you said -- you know, is it fair to kind of lead from here that, you know, obviously the median, the 50th percentile is moving, you know, and you have that, you know, growing? But what is kind of particularly more scary from a resource planning is the distance between the 50th and the 95th, you know, really is growing. And our ability in the past to absorb an event like a 95th percentile is harder now, given the distance. You see that.

So from that, I mean, if you could just kind of speak or validate along those lines and to, you know, like, what are you observing in terms of the demand forecast when you do the peak, you know, 1-in-10, 1-in-20, and those, and the distance between them?

MR. FUGATE: Well, so currently we have not revised our factors that we use to create the one-in, you know, say -ten estimate relative to the one-in-two. And part of that, part of the reason that we haven’t specifically, like what I just mentioned, is that, you know, once you start truncating the historical window, it becomes harder to have confidence in those estimates of the actual factors that you're coming up with.

And then the other reason I've been reluctant to address that for this update is because I think it's something we don't want to kind of backpedal on next cycle, once we do go through this sort of rigorous, you know, more rigorous process of analyzing this question with the climate data. So you know, we have had some -- that has been a pain point for us in the past, you know, producing forecasts that sort of change significantly year to year based on sort of fluctuating assumptions.

So this is one that we are holding constant for this update. And then next cycle, we hope to produce a more robust estimate of what that, you know, 1-in-5, 1-in-10, 1-in-20 factor should be, and also how it might evolve over the forecast period. If you're looking at 15 years, the 1-in-10 relationship to the 1-in-2 may not be the same at the start of the forecast as you might expect at the end of the forecast.

VICE CHAIR GUNDA: You bring up such important points and I really appreciate both of the points you just made in terms of making sure we make those changes and stick with them as we move forward in a deliberate way. But also, like your point on the long term, a distance between whatever we might choose to plan to, whether it's a one-in-two or something else, and the distance from that to a potential extreme event, and how do we then manage such an event, you know, in real time, you know? So that's extremely helpful.

So last quick question and I'll pass on to commission Monahan. Given that we are going into the 2023 reliability cycle, and then what we've done over the last couple of years is we took the demand, mid demand, the peak demand for September, you know, for each hour, and then we looked at, you know, putting a percent PRM on the top of that to estimate a worst-case scenario as a way to kind of figure out how to cover if such a scenario were to manifest. So it's really important, the one-in-two forecast fit between these different vintages as they change.

So what are you -- based on, you know, your slide 24, it's really hard to see how 23 moved, but it's pretty close, the 23 numbers for the peak. Could you explain, like from a numerical value, is it, you know, a couple hundred, few hundred, or what you have?

MR. FUGATE: Yeah, numerically, the delta between -- for the CAISO?

VICE CHAIR GUNDA: For the CAISO, yeah.

MR. FUGATE: Yes. For CAISO 2023, it's about 100 megawatts.

VICE CHAIR GUNDA: Great. And then, I think this is where I would really like to kind of understand; right? Because you just incorporated into your weather normalization this summer, the 2022 summer, and the 2022 summer is like such an extraordinary event, you know, given the last three years. You know, I'm glad that the one-in-two hasn't changed that much, which is helpful in the analysis. But it also kind of like makes the question pop up for me, if the distance between the 1-in-2 and 1-in-10 or 1-in-20 between these two vintages has increased a lot? And I would really appreciate you providing that information once you have that.

MR. FUGATE: Sure.

VICE CHAIR GUNDA: Absolutely.

Okay, so then I'll pass on to Commissioner Monahan.

Nick, incredible gratitude. Thank you for all the work you're doing.

MR. FUGATE: Yes. Thank you for your questions.

COMMISSIONER MONAHAN: So I do have a number of questions. And I'm sorry I missed part one because they probably are mostly being answered in part one.

But Quentin, can you pop on because --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: So I'm wondering, and maybe I'll just start with the first one, the CAISO Transportation Load Shape, can you just talk, I think it's mostly to others, through sort of the uncertainties that you see in this? Because, you know, we have to make a lot of assumptions. So what are sort of the biggest ones that you would characterize as uncertainties in our modeling?

MR. GEE: With the EV load shape in particular?

COMMISSIONER MONAHAN: Um-hmm.

MR. GEE: Yeah, that's a good thing to highlight.

I mean, I think the first thing is that the TOU rates, you know, we're assuming they're static; right? So I think our TOU rates, Lynn might be able to speak to this more precisely, but I think they only officially go out to 2026 or so. Maybe we have the 2027 from some update, but there's a cycle that they go on, and we just have, you know, we have a rough sense that they're probably going to look like what they did before because no one wants to have everybody, you know, running really high at 5:00 p.m.

But there are some challenges with that. We do know that there's Renewable Portfolio Standard requirements that are coming on, I think 60 percent in 2030, so the time-of-use rates might not be so friendly to the, you know, 12:00 a.m. time when the sun is down. They might want to push more towards the midday.

Some other uncertainties, I think we have a pretty good sense of this. We do try to validate each year the kind of general load shape that we see, but we really don't know. There's about 400 meters in the state that are separate, you know, EV-dedicated meters, and there's -- we're coming up on probably a million vehicles, a million electric vehicles in the stock, so 400 chargers is not the most accurate view of what's going on.

So the rest of that, how people are charging, you know, especially when they're home-charging, that's tied into their meter. And so, you know, it could be their fridge that kicked on, it could be the AC that kicked on, it could be they're charging at this time. So it's kind of hard for us to really get in there and see with more detail, like, are they actually charging in this way?

We do have some data, the input data that goes into these load shapes, that's been transformed by the time-of-use rates. That input data is a pretty good sample because we actually have -- purchased some data where we found -- you know, we had several, you know, tens of thousands of charging instances at homes, and then tens of thousands at workplace and shopping centers and all of these different locations, so we do have a good sense of that. But these are kind of old, and they're used as input shapes.

The output shapes are supposed to be TOU responsive. If we bought brand new data, that might be shapes that are already responsive to time-of-use rates. So it's a little bit tricky to kind of tease out everything, but we have a fairly high degree of confidence that, you know, from some studies that are already existing out there, from time-of-use studies that are out there, we have some degree of confidence that this is what we should be expecting.

But there are some just unknowns here. You know, again, it's older data. You know, driver behavior could change. You know, right now, some people are buying electric vehicles. Those are early adopters. Those are people that are more -- they're more kind of jazzed about, you know, hey, look what my car can do and I can put this timer on and I can save money. And then you've got people maybe that are purchasing a car in 2030, and they're like, does it go from point A to point B? Can I charge at home?

And they might not care at all about time-of-use rates.

So we do have some assumptions there. Like we don't know what the time-of-use rates are. We don't know how, exactly how, responsive people will be. So there are some uncertainties there, but I think we have some degree of confidence. It could become just kind of common knowledge like, well, don't charge your car at 5:00 because you're paying twice as much or three times as much, just put the timer on.

So there are some uncertainties there and it's really hard to kind of say with certainty, you know, here's what 2030 will look like. Here's what 2035 will look like. So we're kind of trying to wrap our heads around that as we see more.

And then on top of that, you know, like we discussed on the next slide, which has all the other opportunities where people could be viewing it as a resource, and that could really change the ballgame as well, so, yeah.

COMMISSIONER MONAHAN: Thanks, Quentin.

MR. GEE: Does that --

COMMISSIONER MONAHAN: That was a great summary. And I would also say the medium- and heavy-duty in particular, there’s --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- (indiscernible.) Like we have some data sets for light-duty. We don't have as much for medium- and heavy-duty.

MR. GEE: Yeah.

COMMISSIONER MONAHAN: And just for the public side, too, we are, as an agency, publishing -- you know, responsible for publishing analysis every two years on the 2030 charging needs, and this data -- so we're integrating the data that Quentin is presenting on Demand Forecasts also into that 2127 report. So we're trying to make --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- all of our products just more consistent across the entire Energy Commission as we move forward.

And can we move to -- oh, yeah, we're on it, actually.

So one just minor question is I've heard of like active managed charging and passive managed charging, but not managed charging versus demand response. Is there a reason we’re -- I mean, is there something in the managed charging piece that I'm missing?

MR. GEE: Yeah, so active --

COMMISSIONER MONAHAN: Active managed charging versus passive managed, because they're both managed charging --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- but one is --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- kind of passive and one where basically you say, I'm going to charge my car at this time and I'm hands off, which is how most of most people who, you know, get into the charging of their car, that's how they do it. Whereas demand response is a lot more --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- there's an active -- there's like a third party where there's somebody else getting involved is how I've thought about it.

But can you --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: Is there some nuance in the managed charging piece that I'm just missing?

MR. GEE: I am a little bit, I think, fuzzy in my head about the terminology distinction there. I think we've been talking a lot more from a reliability perspective as opposed to, I think, some of the other frameworks that are out there around managed charging.

I think, if I'm not mistaken, it's been a while since I've done a deep dive into these different issues, but I think managed charging, active, I think if I'm -- I'm a little fuzzy, but I recall something, I think, of passive managed charging is kind of like something akin to time-of-use.

COMMISSIONER MONAHAN: Yeah, it’s time-of-use.

MR. GEE: Yeah, where you're relying on the person to kind of go like, well I don't want to do this, or I'm going to set up a timer, whereas managed charging active might be more like you sign up for a program and you kind of do the tie-in and you would make some kind of agreement, and you set up the framework, you'd say I want to have a certain amount of energy in my battery when I wake up.

COMMISSIONER MONAHAN: Um-hmm.

MR. GEE: But you kind of just set it aside in some kind of aggregator where it’s kind of like, oh, hey, well we can trim demand now, but then catch back up later, save you 50 cents, and then, you know, you still wake up with your car being full.

So that's kind of this more sort of opportunity to sort of really flex the load, whereas I think the time-of-use approach is more just like, well, just don't charge at these times, and do if you really need to.

But, yeah, I'm forgetting a little bit more of the specifics about how these different frameworks are discussed.

I do know that demand response is something where we're not just talking about vehicles, we're talking about all kinds of load shedding-type events where we're kind of asking, you know -- I think one examples is water pumping. Like can you just turn off your pumps for a few hours? You can bring them back on later. And I think that's how we're envisioning demand response in this case where it's like, okay, please don't charge. You know, you have now some aggregator that can control 300,000 cars and they just say, okay, we’re just going to turn all --

COMMISSIONER MONAHAN: Ah, so they’re both active? Both managed charging and demand response are both active? There's a third-party kind of getting involved in this. I didn't understand that.

MR. GEE: Yeah.

COMMISSIONER MONAHAN: Okay.

MR. GEE: Yeah. I think that would be the way to think of it, yeah.

COMMISSIONER MONAHAN: Okay.

MR. GEE: But that's a good point. I should double-check and make sure that the terminology with the active and managed -- or excuse me, active and passive is clear there.

COMMISSIONER MONAHAN: And then can we move to slide 17? Because that's where I had a lot of questions. And this is where I think you covered it in the last workshop, so I'm sorry I missed it.

MR. GEE: Yeah.

COMMISSIONER MONAHAN: Two things that -- there we go --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- surprised me were the reduced VMT forecast, and just the fact that our forecast shows higher demand with AATE than with our 2022.

MR. GEE: Yeah.

COMMISSIONER MONAHAN: That was a surprise to me.

MR. GEE: Yeah.

COMMISSIONER MONAHAN: Can you -- like reduced VMT forecast, where is that? Why is that?

MR. GEE: I think it’s we caught, I think, an anomaly in the 2021 IEPR --

COMMISSIONER MONAHAN: Oh, right.

MR. GEE: -- where the ZEVs --

COMMISSIONER MONAHAN: Okay.

MR. GEE: -- were just getting more VMT. So ZEVs kind of already have more VMT because they tend to be newer.

COMMISSIONER MONAHAN: Right.

MR. GEE: And so like an ‘86 Buick is not driven as much as a 2020 Model 3 or whatever, so there's that phenomenon going on.

But there was something else in the coding that I think was assigning too many vehicle miles --

COMMISSIONER MONAHAN: I remember. Okay.

MR. GEE: -- to those. And so that reduced -- the vehicles themselves were more efficient.

And then there was an error with the plug-in hybrid electric vehicles where not only do they have the VMT that was a little high that we improved, but we also found that there was a disaggregation coding error where it was assigning all of their miles as electric and not --

COMMISSIONER MONAHAN: Okay.

MR. GEE: -- split between electric and gasoline. Yeah.

COMMISSIONER MONAHAN: Thank you. I actually thought that the model had changed to reduce VMT and I was like, wait. What?

MR. GEE: No, no. Yeah.

COMMISSIONER MONAHAN: But that makes perfect sense.

MR. GEE: No, no. No fixing that. We do have --

COMMISSIONER MONAHAN: I’m like, that's not happening yet --

MR. GEE: Yeah.

COMMISSIONER MONAHAN: -- until CARB releases regulations that would require that.

MR. GEE: Yeah, I believe VMT per capita actually goes up in our forecast.

COMMISSIONER MONAHAN: Yeah.

MR. GEE: And that's primarily --

COMMISSIONER MONAHAN: That makes --

MR. GEE: -- because, yeah, people drive more when the economy's larger per capita.

We do have a new vehicle -- excuse me, a vehicle miles traveled or a travel model that we're working on with some consultants at ICF that are really helping. We're going to be integrating that with CARB's EMFAC travel approach. And we are looking forward to that because that will give us a little more flexibility to model out some of the consequences. What if we can get VMT down? But also what if, you know, autonomous vehicles take over and there's just a lot more, you know, vehicle miles traveled associated with deadheading and that sort of thing?

COMMISSIONER MONAHAN: Thanks, Quentin. This is super helpful.

And as always, thank you for your thought leadership on this. I mean, I just think you're always thinking kind of outside the box, but you're also going in the box deeply to understand what's happening in modeling. So just appreciate the work that you and your team are doing on this.

MR. GEE: Great. Thanks, Commissioner Monahan.

VICE CHAIR GUNDA: Thank you, Commissioner.

Commissioner McAllister, I see you online. Do you have any questions?

COMMISSIONER MCALLISTER: No, I don't. I've had to be in and out, so I didn't want to -- I don't have any questions. But, yeah, I'll have a look at the full presentation since I missed part of it.

VICE CHAIR GUNDA: Thank you, Commissioner McAllister.

Quentin, I just want to elevate a couple of things that Commissioner Monahan mentioned.

As we go into the DER proceeding, you know, the kind of workshop that we're thinking, I would like you to please review the discussion at the business meeting if you didn't follow that, the conversation between myself, Commissioner McAllister and Commissioner Monahan, on kind of the importance of some key elements that we discussed on the coordination between EAD efficiency, as well particularly clean transportation, on some of these conversations that you just raised. I think it's really important to scope the workshop, taking into account the broader integration, and how -- you know, the grid friendliness of the electric loads and the grid management opportunity.

Second, I think the one that she raised that was really important for me was to like the terminology, you know? And I know Commissioner McAllister kind of wants us to move away from saying demand response and then move to better ways of discussing that. It would be really helpful to standardize those terms as an agency when we talk about them, and also kind of socialize with our colleagues at other agencies so that we're all speaking from the same thing.

And finally, on the charging profile that you shared, you know, as you know, again, this is elevation, one of the criticisms that we received in the media and questions during the heat wave was, you know, why are you electrifying transportation if you can't keep the lights on in California, right, kind of thing?

So you know, it's really, I mean, the load shape, really, you know, is just the backbone of the conversation, and then our ability to potentially then help the grid on the top of not only managing it. So you know, kind of elevating that conversation, either in this IEPR or in the proceeding, to really lay that out.

The way we have the medium- and heavy-duty charging profile layered out is a lot smoother than I would expect. I'd probably expect it to be much more lumpier in its charging, given the kind of core and sectors. So putting in money, time, like if resources are the issue, I think we should pull together the resources to either get the data, continually monitoring the data, however, you know, to better understand charging profiles, given Commissioner Monahan's comments on consistency across 2127 and the forecasting products.

Lastly, I would, you know, given that we now have the IMD data, you know, the IMD data -- or the virtual auditing using the IMD data is a lot more feasible for low-frequency, high-amplitude loads; right? So it would be -- and I just want to at least explore with colleagues, you know, in academia who are studying the IMD data to virtually assess the profiles and how much we can glean from the meter data directly. Composite meter data on the charging profiles would be an important element to dig into.

So I just want to elevate those topics.

As Commissioner Monahan said, excellent work. So just to you, Heidi, Nick, Lynn, you know, the team, it's just an A-plus team. And I think I see how much we in the front of the curtain and also behind the curtain. I mean, I think the Forecasting Team is one of those teams that generally is moving so much from behind the scenes, so thank you so much for the work.

Thank you.

MR. GEE: Thanks, Vice Chair.

VICE CHAIR GUNDA: So we can go to Q&A, I think; right? Is that the next thing? I'm sorry.

MS. JAVANBAKHT: Yeah, I think that is the next thing.

And we just have one question in the Q&A, and it's for Quentin on that first chart that you showed.

So, the question is around --

"The daytime charging seems significant, which would correlate with workplace charging. Right now there is a lack of workplace charging. Does this shape reflect charging asset availability, or does it just look at energy costs and assumes there is enough charging infrastructure to serve all TE load at all times?"

MR. GEE: Yeah. That's a really good question, Bill.

Yeah, so really the model -- so the model does indirectly look at charging, kind of in the way you're describing in terms of availability, in that there are these input actual data from chargers where we know that people were charging in a particular way. And we're talking not just like looking at one person, but we're looking at, I believe, tens of thousands, if not hundreds of thousands -- hundreds of thousands of total datapoints, but also tens of thousands, I think, in different categories of charging events. So I think we have some pretty good confidence with those in terms of how are a lot of people trying to charge.

But you are correct in the sense that, really, we kind of take that and we assume, more or less, that the load shape will look like that, and then the input load shape looks a certain way, and then we have the time-of-use modification as a result. And that just does kind of assume more or less that, you know, people can charge when and where they want, or they otherwise will be charging when they want associated with those input load shapes. So that's a good point.

As far as workplace charging goes, that’s like a good example. So the chart sort of shows your 5:00 to 9:00 or 4:00 to 9:00 time period is kind of low because no one wants -- why not save some money? And it's easy if you have a timer. So there's that kind of low period.

But the energy demand has to get pushed into other parts of the day, and so we see a little bit of a hill in the midday, and we see kind of a big hill towards the end of the day. So that hill in the middle of the day, roughly would, most likely -- we don't -- we're not saying that, you know, these charges are here that, you know, we're not doing sort of a bottom-up analysis of where the chargers are, but that would lend itself to saying, actually, workplace charging is a really important opportunity, given the way that rates are structured.

And given that workplace charging is an opportunity, what we should be doing and, you know, what actually the Fuels and Transportation Division, which Commissioner Monahan works with or oversees and the Clean Transportation Program there, you know, this is kind of a signal to them. Hey, you know, there's a lot of opportunity based on saving people as much money as possible, helping the grid out, those sorts of things. So workplace charging is something that they're looking at closely in terms of their funding priorities for infrastructure. But our model itself doesn't say, you know, here are all the chargers, you know, we have enough workplace chargers in place.

So yeah, we don't know how things are going to look exactly in 2030. This is a sort of broader econometric sort of analysis, as opposed to a bottoms-up, like here's where we need the chargers.

MS. JAVANBAKHT: Thanks Quentin.

There are no more questions in the Q&A, so I will hand it back to Heather.

MS. RAITT: Thank you, Heidi.

And thank you, Quentin, for all that great information.

So we will now move on to our public comment period. So folks who are attending, if you would like to make a comment, please press the raise-hand function to let us know that you want to comment. And if you are on the phone you can press star nine.

I will give it a moment. I'm not seeing any raised hands, but we'll give it another moment here. So if you want to comment, raise your hand. And then if you're on the phone, press star nine.

Okay. Oh, here we go. Bill Boyce, if you would like to go ahead?

MR. BOYCE: Good afternoon.

I was going to point out, and I kind of made this comment last week, as well, I think going forward --

MS. RAITT: Oh, I’m sorry, Bill.

I should have said could you please state and spell your name and give your affiliation for the record before you begin?

MR. BOYCE: Bill Boyce. Bill Boyce Consulting, representing the West Coast Clean Transit Corridor Initiative.

Wanted to kind of reiterate some comments I made last week which are really going forward in the IEPRs. The grid-side infrastructure to serve all the TE load is going to become very important and recognizing that the generation assets are paramount for, you know, the current IEPR. But delivery of that electricity as a statewide asset is something else we need to become aware of and modeling. And I think there were some comments that we're going to be taking a closer look on that.

But I think it's going to be very important with regards to that serving that load that we start to really look at the distribution and transmission assets. And that is going to become an equally important resource in meeting the state's carbon reduction goals.

So I'll be submitting some comments in a couple of days on that but wanted this opportunity to kind of hammer that home a little bit more.

Thanks.

MS. RAITT: Thank you.

Anyone else has comments, just raise your hand please.

Alright, well, not seeing any more comments, I think we're done with public comment period.

VICE CHAIR GUNDA: Thank you, Heather.

I'm guessing that's the last IEPR workshop for the year, which means we won't have any more fun days for the rest of the year.

MS. RAITT: Yeah, you get two weeks off --

VICE CHAIR GUNDA: -- we’ll miss out.

MS. RAITT: -- from workshops.

VICE CHAIR GUNDA: You know, I just wanted to share in closing, IEPR -- Heather, IEPR is such an important product and, you know, you guys do it so well, the IEPR Team. And it's such a wonderful venue for important conversations for the State, you know, an important opportunity for the public to comment, and all sorts of stuff. So I just wanted to say, Heather, thank you for your long work and partnership and the opportunity to work with you on the 2022 IEPR.

Look forward to getting into the next year. And for everybody who were in attendance, thank you for taking the time to join us. Thank you for your participation and comments. And happy holidays to you and your families and loved ones. I look forward to coming back in January, so thank you all.

And with that, I adjourn the meeting. Thank you.

(The workshop adjourned at 3:28 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.

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IN WITNESS WHEREOF, I have hereunto set my hand this 13th day of January, 2023.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

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Martha L. Nelson

MARTHA L. NELSON, CERT**367

January 13, 2023