DOCKETED	
Docket Number:	21-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	240011
Document Title:	TRANSCRIPT 8-5-21 Session 1- IEPR Commissioner Workshop on Data Inputs and Assumptions for 2021 IEPR Modeling and Forecasting A
Description:	TRANSCRIPT 8.5.21 SESSION 1 OF 2 - IEPR COMMISSIONER WORKSHOP ON DATA INPUTS AND ASSUMPTIONS FOR 2021 IEPR MODELING AND ACTIVITIES - IEPR MODELING AND FORECASTING ACTIVITIES - 2021 ENERGY DEMAND FORECAST MODELING UPDATES AND FUTURE VISION
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Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	10/7/2021 5:10:32 PM
Docketed Date:	10/7/2021

STATE of CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of,	) Docket No. 21-IEPR-03
	)
2021 Integrated Energy Policy	)
Report (2021 IEPR)	) Re:Data Inputs and
	) Assumptions for 2021
	) IEPR Modeling and
	) Forecasting
_____	) Acitivities

IEPR COMMISSIONER WORKSHOP ON DATA INPUTS AND

ASSUMPTIONS FOR 2021 IEPR MODELING AND

FORECASTING ACTIVITIES

REMOTE ACCESS ONLY

THURSDAY, AUGUST 5, 2021

1

SESSION 1 OF 2: 2021 ENERGY DEMAND FORECAST MODELING UPDATES AND FUTURE VISION

10:00 A.M.

Reported By:
Martha Nelson, CERT. 00367

APPEARANCES

Commissioners Present

J. Andrew McAllister, IEPR Lead Commissioner

Siva Gunda

Patty Monahan

Staff Present

Heather Raitt, Program Manager

Raquel Kravitz, IEPR Team

Matt Coldwell, Demand Analysis Office

Cary Garcia, Demand Analysis Office

Nick Fugate

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Public Comment Moderator

Dorothy Murimi, Public Advisor's Office

Public Comment

Kyle Navis, CPUC

INDEX

P R O C E E D I N G S

AUGUST 5, 2021 10:00 A.M.

MS. RAITT: Okay. Well, good morning everyone. Welcome to today's 2021 IEPR Commissioner Workshop on Electricity and Natural Demand Forecasts, Inputs and Assumptions.

I'm Heather Raitt, the Program Manager for the Integrated Energy Policy Report, which we refer to as the IEPR.

This workshop is being held remotely consistent with Executive Order N-08-21 to continue to help California respond to, recover from, and mitigate the impacts of the COVID-19 pandemic. The public can participate in the workshop consistent with the direction in the executive order.

Today's workshop has a morning and afternoon session, and a separate login for each.

To follow along, the schedule and slide decks have been docketed and posted on the CEC's website.

All IEPR workshops are recorded and the recording will be linked to the CEC's website shortly following each session. A written transcript will be available in about a month.

Attendees have the opportunity to participate today in a few different ways. For those joining

through the online Zoom platform, the Q&A feature is available for you to submit question. You may also up vote a question submitted by someone else. Click the thumbs up icon to vote. Questions with the most up votes are moved to the top of the queue. We'll reserve a few minutes at the end of the morning to take questions, but likely will not have time to address all the questions submitted.

Alternatively, attendees may make comments during the public comment period at the end of the morning and afternoon sessions. Please note that we will not be responding to questions during the public comment period.

Written comments are also welcome and instructions for doing so are in the workshop notice. Written comments are due on August 19th.

And with that I'll turn it over to Commissioner Andrew McAllister. Thank you.

COMMISSIONER MCALLISTER: Thank you, Heather. I am Commissioner Andrew McAllister, leading this year's IEPR. And I'm joined on the dais with two colleagues, Commissioner Siva Gunda who is the lead of the Energy Assessments Division, and the forecasting that happens within that division, so lead commissioner on this topic today. And Commissioner Patty Monahan, lead on

transportation, which we'll be talking about in the afternoon.

So, I think I'll just point out high level that this forecasting work really is the bread and butter of what the Commission does. And its importance is really higher than it's every been, I would say, in the history of the Energy Commission. And this authority and this activity is really pursuant to the original authority that the Commission was formed to implement in that, you know, 45 plus years ago now.

And as we move towards a zero carbon electric grid and also sort of deal with the corollary issues on the other side, the natural gas system, the forecasting work just takes on new importance in a number of different ways. And, obviously, the products that the forecast is asked, has been asked, and will increasingly asked to produce are ever more granular, and ever more temporal, and ever more critical particularly in summers like we're having this summer and will, presumably, continue to have going forward in terms of producing peak forecasts. In terms of really being the materia prima that both the PUC's IRP and procurement activities emerge from or they're built upon. And then also with the ISO, the transmission planning, and many, many other things that the ISO does. And so, the forecast really

is a key resource for the state.

I will say, I just have to give our staff, and Commissioner Gunda and team, Aleecia, Deputy in the Assessments Division, and the whole forecasting team that you'll hear from today massive kudos for the quality of their work over the past years. Even with these challenges that we're seeing with reliability, and peak demand and, you know, the stress that we're seeing on the grid, the evaluation, the retrospective look that we've given every aspect of the forecast in years past, they have held up to robust inquiry. The forecasts that we have produced in the past have proven out to be very close to what actually happened, even in these times of stress.

And so, I just want to give the whole team credit for that because it often seems dry when we have these workshops. You know, we do the forecast, you know, demand, then we back out, you know, and add to and subtract from that base forecast with all the different adders that we'll hear about today including, you know, energy efficiency, and transportation demand, and the like. And we're doing a fuel substitution forecast this year. And, you know, the behind-the-meter solar forecast. All of these elements of the forecast really do combine to produce quite robust results. And we're

always, you know, staff I think is always trying to improve each of those elements.

So, I just -- just a preamble to just give a preemptive thank you to the staff because they're world experts in this topic. And, you know, a lot of states actually do look at California, their PUCs, and their balancing authorities, and their state energy offices look at California in the process. And I think sometimes they're a little bit flabbergasted at how much detail we get into because most states just don't have the resources to do that. But we do here in California. We're lucky that we do because it really helps us get to a better planning outcome.

So, with that I will -- thanks for bearing with me on that and I'll pass the microphone to Lead Commissioner Siva Gunda.

COMMISSIONER GUNDA: Thank you, Commissioner McAllister. As always, it's really wonderful for you to set the stage because you have such a long kind of term context in what we're doing. So, thank you for your remarks and kind of setting the context.

As always, I'd like to say an opportunity to just say I have the privilege of being on the dais with you, my mentor in the forecasting, and my colleague now. And Commissioner Monahan, it's been just a pleasure to

work on the transportation side. So, just thanks to both you for your leadership on broadly the IEPR, but also the transportation, evolving the analytics and everything on all fronts. So, just thanks to both of you.

As always, you know, we should never lose an opportunity to thank Heather and her IEPR team. And I don't know how we do this day after day. Heather and the IEPR team, thank you so much for your wonderful work.

And just to kind of point on what Commissioner McAllister was saying that we have a well cast team. The team that's just only not, you know, analytically rigorous but just generally collaborative and generous staff that we have here that look at every opportunity to move forward the things in a collaborative, transparent fashion. And I just want to give absolute kudos to every single person who is involved in developing the forecast.

Obviously, you know, some of them are in the -- you know, front facing. But I do want to recognize the front facing of the leadership, Nick Fugate, Cary Garcia, Matt Coldwell, Aleecia, and the entire team. And just kudos to every single one of you for all the different meetings that you do behind the scenes. The

DAWG meetings, the JASC meetings and such to kind of continually move this forward.

As Commissioner McAllister said, and I do not want to repeat what he set up. I know it's a core function for CEC that it does kind of become an integral part of a number of long-term planning activities. The IRP process at CPUC, the transmission planning, the resource adequacy, so it forms the basis of so many important work for California.

Just one thing that I want to highlight here today is the changing nature of the electricity planning. And as Commissioner McAllister noted, we are really in a kind of a transitional period, very much similar to how the CEC's formation was around. CEC was formed around a transition of the energy system and we're again in that place where you have the goals of SB 100 setting the stage for 2045. Policy-driven goals, the governor's bold and ambitious goals on electric vehicles and such, but also in the backdrop of a reliability crisis.

So, we really have to figure out how to evolve our analytics in a way that they really address and provide an opportunity for the decision makers and the planners a wide array of tools and analysis that help move the state forward through this next five years, but

also towards our goals of 2045.

Specifically, a couple of things is, you know, history is definitely not indicative of the future anymore, both from a policy stand point, policy is evolving very rapidly. Climate change is evolving very rapidly. And the attitudes of people and customers is changing rapidly.

So, we're in this evolutionary period. So, and I just want to thank staff for taking all this into consideration as they develop this. I'm really looking forward to Matt Coldwell's presentation on setting the stage for the future of the forecasting.

With that, I will pass it on to Commissioner Monahan.

COMMISSIONER MONAHAN: Well, thank you. And to both Commissioner McAllister and Commissioner Gunda, I just want to say I mean this work, as you all know, is more important than ever. And your leadership, I really just respect all that you are doing to ensure that we have a safe, reliable, affordable energy system.

And as both of you have emphasized, I mean this year perhaps more than ever we need to ground our state's energy planning in strong analysis. And the work of the Energy Commission, in collaboration with

CAISO and CPUC is more critical than ever before. I mean, last year we had nine flex alerts. This year I want to say we've had five. Is that right? Commissioner Gunda, you would have an answer to that.

COMMISSIONER GUNDA: We had six.

COMMISSIONER MONAHAN: We had six. We're at six.

COMMISSIONER GUNDA: Yeah.

COMMISSIONER MONAHAN: And we still have a long way to go. And, you know, our hydro is way down this year. There's grid stress across the entire west. There's, you know, wildfires really causing devastation in California and beyond, that we know are increased in severity as a result of climate change.

So, we're -- you know, at the one hand we need to move as quickly as possible to a clean energy system, on the other hand we have to make sure there's a reliable energy system. And a proclamation was just issued that opens the door for more generation, but that generation carries a cost in terms of air pollution.

So, again, I just want to appreciate all the staff is doing around analysis for California energy planning. And really look forward to the conversation today. I think there's an air of -- I mean we all feel pretty somber about the situation. And I think that's

coloring this series of workshops in terms of, you know, we know that we're not where we need to be in terms of having a resilient energy system. And there's a commitment from all the state agencies to do more to ensure that Californians can feel comfortable with their energy system.

So, I look forward to the conversation. I think I'll stop there. And thanks to everybody on the IEPR team for organizing this series of workshops.

MS. RAITT: Great. Thank you, Commissioner.

COMMISSIONER MCALLISTER: It's back to you, Heather. Thank you.

MS. RAITT: Great. Thanks. So, this is Heather. So, today we actually have a series of presentations from the Energy Commission staff. And as Commissioner Gunda mentioned, the first one is Matt Coldwell, who manages the Demand Analysis Office here at the Energy Commission. So, Matt, I'll go ahead and hand it over to you. And let me make it so you can put your video. There you go.

MR. COLDWELL: Thanks Heather. It wasn't letting me put my video on there for a second.

So, thanks Commissioners for sort of setting the context of the day. You all highlighted some of the key issues that the forecasting team is considering and

considering how to reflect in the forecast moving forward. And so, we'll talk a little bit about that today. And so, I guess Heather, or whoever's controlling, so just go to the next slide here.

I wanted to start off my short presentation just kind of going over what the goals of this workshop are. So, this is a workshop on the 2021 California Energy Demand Forecast, and we're covering several of the inputs and assumptions that go into that forecast.

And really, sort of the overarching goal is to provide information and solicit feedback on those inputs and assumptions that we're utilizing this year.

And so, we do this workshop every IEPR cycle for several reasons, but two of the main reasons is to provide kind of a level of transparency to how we develop the forecast, and also to provide stakeholders and interested members of the public an opportunity to comment on the work that we're doing.

And so, the list here that you're seeing on this slide is a kind of an overview of the different topics that we'll be covering today. We'll be hitting on kind of an overview of the process, and model updates that we've made this year. And then, historic energy consumption and weather trends, as well as zero-emission vehicle trends. And then, we'll be doing a presentation

on reflecting the potential increase in building electrification over the forecast horizon. And then, there'll be a presentation on the retail rates.

So, the next slide. So, it's also good, I always like to start, you know, talking just a little bit about why we do a demand forecast.

And so, the Warren-Alquist Act established the Energy Commission back in 1974 to respond to the energy crisis of the early 1970s, and the state's unsustainable growing demand for energy resources.

So, the statute that you're seeing here, 25301, really gives the CEC broad authority to conduct energy demand forecasts and assessments. And so, the California Energy Demand Forecast is really the vehicle for the CEC to satisfy its statutory requirement here. Although, to be honest we don't really look at it as just a requirement, we really look at it as, you know, our contribution to statewide energy planning and really as a service to all Californians.

So, the next slide. So, the California Energy Demand Forecast is not just a single set of numbers. It consists of several different forecasting products that are used for a variety of different purposes in various energy planning processes throughout the state, and with our planning partners, who you're seeing here.

And so, we work really closely throughout the year with the California Public Utilities Commission, the California Independent System Operator, and the Air Resources Board, as well as several other key stakeholders like the state's utilities, in developing the forecast. And each year we memorialize which forecasting products that we develop are used across the various planning processes. We do that in the IEPR with what we call the single forecast set language. It's in every version of the IEPR.

The next slide, please. So, you know, of course the -- you know, in the forecasting world, you know, it's important to recognize that the world around us continues to change. And the Commissioners all touched on this. And those changes, both, you know, small and large often have an impact on energy demand.

So, this is not by any means an exhaustive list of things that -- you know, of things that create uncertainty in forecasting, but definitely things that are on top of mind at the moment.

So, you know, just state, California's policies for decarbonization. So, that's across the economy but really, you know, on the transportation and the building side is becoming, you know, more and more critical for us to be able to look at those decarbonization policies

and translate that into energy consequences and reflect it in the forecast.

And so, on the transportation side, from a policy stand point I think, you know, Governor Newsom's Executive Order N-79-20 is sort of the most critical one that we are looking at right now. And so, in sort it's, you know, 100 percent of in-state sales of new passenger cars and trucks will be zero emission by 2035, and the same in the medium-duty and heavy-duty sector by 2045.

And so, this obviously has implications, huge implications for a fuel demand shift from sort of traditional transportation fuels, such as gasoline and diesel, over to sort of electricity demands, and other cleaner fuel demands as well. So, being able to reflect that in an electricity forecast, the transportation sector's contribution in the electricity forecast is really critical and we'll be talking a bit about that today.

On the building side it's sort of the same case. You know, there's a continued push for building decarbonization strategies in the state that really will have an effect both on electricity and gas demand in buildings. And that includes energy efficiency measures, electrification, load flexibility, and several other strategies that will have an impact on energy

demand.

The frequency of extreme weather events. This was touched on as well by the Commissioners. So, the recent extreme weather events have not only stressed our energy systems, they're really forcing us to rethink how we incorporate the effects of these events on energy demand.

And then COVID has sort of turned our world upside down, really. And, you know, there's obviously the short term effects of COVID in stay-at-home orders, but likely there will be continued structural, economic structural shifts that occur because of the experience over the last 16 or 17 months. And, obviously, remote working is a critical piece of that. I'm here in my home office giving this presentation today. And several other people are likely at home working as well.

That has huge implications for shifting demand from the commercial sector to the residential sector. It has implications on, you know, the way we travel, you know, commute miles, you know vehicle miles traveled.

So, even, you know, things like transit ridership are being -- have been really impacted by the effects of COVID. And I was just looking at BART ridership data this morning, because that's what I do for fun in the mornings. And just as an example, on

Tuesday, this past Tuesday, August 3rd, ridership for BART was only 21 percent of pre-COVID projections for a typical weekday in August. So, you know, people are moving around much differently now than they were before COVID.

And then, I have shopping and dining here, just as examples of everyday activities that have been impacted by COVID, and the potential for sort of the lasting effects of that. So, you know, online shopping, Uber Eats, all those things that really have changed the way consumers conduct sort of their everyday activities.

So, the next slide. So, because the world and energy demands continue to change around us, so must the way we forecast energy demand.

So, how must the forecast continue to evolve to capture that uncertainty from things like changing climate and changing policies? And so, this is something that we've been thinking about quite a bit lately.

And a few examples of how our forecast is continuing to evolve is, so scenario developments to capture short- and long-term uncertainties. And so, the additional achievable framework that we use, which was originally designed for energy efficiency scenarios, or what we call AAEE in forecast speak. So, we are looking

at, you know, how can we expand that framework to develop a set of scenarios for some of these emerging issues. So, including fuel substitution, or what is also called building electrification which really, you know, to design a set of scenarios to really capture the range of uncertainty when it comes to building electrification over the forecast horizon that will be occurring in California's new and existing building stock.

And so, Ingrid Neumann will be providing a presentation on this a little bit later this morning.

We're even considering using that framework for transportation electrification, too, because there's uncertainty, you know, how that will -- you know, how the zero emission vehicle market will evolve between now and 2035 and, obviously, beyond that as well.

And then, Long-term Energy Demand Scenarios Project. This is a new project that we are undertaking. It's different from the planning forecast that you'll be hearing about today. That's based on economic trends, and other inputs and assumptions.

Really, these long-term scenarios will be designed to identify different pathways to achieve some of our longer-term climate goals. So, we'll be actually hosting a workshop on these demand scenarios a little

bit later this year. I think it's scheduled, for now, on December 16th.

And then, of course, there's, you know, looking at improved climate projections to reflect the frequency of extreme weather events. So, I don't think it's too bold for me to say that climate change is here and recent extreme weather events in California, the rest of the west, and the rest of the world, really. They're scary, but they are real and have a real impact on energy demand and system planning.

And so, we've been working with our Energy Research and Development Division on better incorporating these events into our forecast. And Nick Fugate will be discussing this a little bit later this morning.

Then, of course, there's continued coordination with our planning partners. I identified, the CPUC, CARB, and the ISO earlier on. But other stakeholders as well. So, we have a robust process for developing the forecast that includes workshops like this. We have more technically focused working group meetings that we call DAWG meetings, DAWG being an acronym for Demand Analysis Working Group. And then, of course, we have a lot of interagency collaboration and coordination, as well.

And so, you know, we look forward to continuing working with our planning partners and other stakeholders to, you know, identify how the forecast must continue to evolve to be able to reflect the uncertainty that, you know, climate, and policies, and economic shifts are creating.

The next slide. And so, that was my last slide. So, I will stop there and say thanks again to the Commissioners and to Heather.

MS. RAITT: Great. Thank you, Matt, appreciate that.

And so, our next presentations are from Cary Garcia and Nick Fugate. Cary is the lead forecaster responsible for coordinating many of the technical elements of the IEPR Demand Forecast. And Nick is the lead forecaster responsible for developing many of the major components of the forecast.

So, Cary, I'll hand it over to you. Go ahead, thanks.

MR. GARCIA: All right, thank you Heather, I appreciate that.

Yeah, if you can move to the next slide? We'll pause here for a moment so --

MS. RAITT: Oh, Cary, we're not hearing you. Cary, I don't know if you can hear me, but we're not

hearing you.

MS. KRAVITZ: I think he lost connection.

MS. RAITT: Okay. We might need to go to Nick.

MS. KRAVITZ: Nick, are you there?

MR. FUGATE: Yes.

MS. KRAVITZ: Okay, I'll move to your slide.

MS. RAITT: Sorry about that. So, we'll go ahead and it won't be in order, but we'll hear from Nick and then we'll work on getting Cary's audio. Unless maybe he's going to have audio again right now.

Now you're muted Cary. Do you want to try unmuting?

MR. GARCIA: How about that?

MS. RAITT: There, now we hear you.

MR. GARCIA: Oh, gosh. Yeah, I guess it kicked me off. It kicked me off there for a second.

MS. RAITT: Should we try it again? Should we go back to Cary's slide.

MS. KRAVITZ: Yeah.

MS. RAITT: Thanks for your patience, everybody.

MR. GARCIA: Apologies for that. You'll notice it kicked me off the call. I guess if I don't say anything for a while it will assume I'm not on there anymore. That's probably what happened.

Okay. Yeah, we can just go to that forecast

process and overview, and hang out there for a second.

So, good morning, Cary Garcia with the Demand Analysis Office. So, this morning I'm going to start my presentation with an overview of our forecasting process and then follow that up, as you saw on the agenda, with a discussion about modeling updates. From there, I'll get into how we organize our assumptions and then finish up with some historical comparisons in terms of energy demand.

But before I start, I wanted to thank our data collection team in the Data Integration and Policy Office here at the Commission. They pull together our economic and demographic data, as well as our demand data. And we asked them to do this task just slightly ahead of schedule, specifically for today so that we could have it to provide information here at this workshop.

So, specifically I would like to thank Julianne Alontave and Cam Nguyen. They prepare our electricity and gas demand data. And then, I'd also like to thank Nancy Tran who helps prepare our economic and demographic data.

And so as you'll see today, those are kind of key pieces to our forecasting work, really key input. And so, they did a tremendous amount of work behind the

scenes to get that done for us, so I just want to extend an early thank you to the rest of our team here at the Commission.

The next slide. So, to start things off I wanted to highlight a few things. First, you'll notice the title of our demand forecast. You know, shorthand we'll call it the CED 2021, but the full name, you know, California Energy Demand Forecast 2021, forecasting 2021 through 2035.

So, typically we'll prepare a 10-year forecast, but we have extended this horizon, forecast horizon this year out to 2035, and since that will be an important year to plan for due to the governor's executive order regarding zero emission vehicles. So, I wanted to highlight that.

Also, another little bit of different in our forecast this year is that we will not be preparing a preliminary forecast, unlike other odd year IEPRs. We typically run our models shortly after we've finished our forecast update, which we had prepared in 2020, producing a preliminary forecast and then running the models once again, so what we call our revised forecast, with some updated economic and demographic data.

But, you know, running our full suite of models takes a lot of resources so, you know, it really limits

the time that we have to really focus on model improvements. You know, when we're trying to put together two forecasts our efforts historically -- it's coming up to update three forecasts in a really short amount of period of time.

So, instead of trying to fit those backdraft forecasts into, you know, the limited window that we have, but instead we're trying to focus on producing one forecast where we can release the forecast results a little bit early. Essentially, draft versions of our forecast forms should be available to the public in early and mid-November, as you can see on the schedule here. So, stakeholders have more time to see our detailed forecast results.

And aside from those changes, we will have our final forecast workshop on December 2nd, and then plan on adopting that forecast at a CEC Business Meeting in January, as usual.

And then, lastly, I want to bring attention, I think Matt had mentioned it as well, just wanted to bring some attention to the Demand Analysis Working Group, or DAWG, where we'll be hosting several meetings along the way as we prepare our forecast, discuss some more details of our forecasting work.

So, the link I have there on the bottom of the

page, that will take you to our website, so the website for the DAWG meetings, or you can sign up for email notifications so you can get updated on when the next DAWG will be posted.

The next slide. So, now I'm going to start getting into our forecasting process. So, sometimes we'll gloss over some of these details, but I thought it was a good time to have a little primer on the basics of our forecasts and how this all gets put together. So, I'm going to try to cover that here, this morning.

So, I want to start off with the basic geography of our forecasts. We produced end use demand forecasts for both electricity and gas. So, we separate the state into different planning areas that are associated with specific utility areas in the state.

You can see here the entire level planning areas, you have eight for the electricity sector, and you can also see they're closely aligned with the utilities that serve those particular areas.

And then, we also have a set of gas planning areas, about four of those is what we have here, also aligned with the specific gas utilities in the areas they serve.

But if we go to the next slide, we could see that, as Commissioner McAllister mentioned, we also

decided to get a little bit further than that.

Can you move to the next slide, please? So, here on the right-hand side you can see a map. And this is our 20 forecasting zones. So, what we're doing here is some of the planning areas that I showed on the previous slide, we disaggregate our forecasts into what we call forecasting climate zones, or just our forecasting zones is what we refer to that internally.

So, not to be confused with another set of zones out there, which are the building zones that are used by our Efficiency Division. These ones are a little bit different in that we try to represent subareas within the larger TAC areas, or transmission access charge areas that are used by the California ISO to differentiate the different parts of the larger system.

So, the same on the left, you can see how we break out the PG&E and Southern California Edison TACs into different subareas. You'll notice that the San Diego Gas & Electric is not on that particular table, which in this case there is only one planning area and one zone. If you look at the map there on the right, you can see it essentially covers San Diego County and a portion of Orange County.

To that point, we also don't show in that table the other smaller POU planning areas because they aren't

subdivided. So, there's also, basically, a one-to-one match between the zone and the planning area.

But the objective here, as I said, is to, you know, take into account the diversity in that particular larger TAC area so we could have more, you know, accurate forecasts at a disaggregate level.

And then I'll also highlight a difference there on the bottom of that table, you know, that I called out as our Northern California Non-California ISO. Pardon us for not creating creative with that, but that's for -- but that's essentially going to be, you know, breaking up the balancing authority of Northern California into different areas where we call out SMUD, the remainder of BANC, and we also add in the Turlock Irrigation District into that larger planning area as well.

Then, so in the next slide I'm going to start getting into -- you know, after I explain our geography here I want to get into sort of our system and how we, you know, coordinate our forecasting work. So, I'm just going to provide a general walk through of the system.

Typically, we would provide just a very scary that has all of the different forecasting pieces flowing into each other, but I thought it would be good to take the time to make that a little less scary, and a little

bit more clear about how we put this forecast together.

So, as the name implies, we have a system of models that coordinate. As I said, sometimes it is hard to digest, I guess, hopefully, I can provide some clarity on this today.

As I mentioned, you know, there's a few keystones here. And the key one focusing on this slide is the historical energy demand data. So, that is the starting point for our modeling. You need to have a good understanding of history to get a sense of, you know, how different parameters will change in the future.

So, for each forecast we compare and update our historical estimates of electricity, as well as gas consumption data. And we organize the data by particular sectors or NAICS categories that are required by the specific model.

And the proliferation of self-generation generating technologies, like behind-the-meter solar, we also need to include an estimate of self-generating electricity. Because our objective here is to model consumption, not just the electricity sales. And so, that sort of creates that linkage between consumption and economic activity that we need to produce these forecasts.

So, the chart, in the graph just there, we can see how the self-generation model is estimating historic self-generation, feeding that to our data collection team where they put that together and organize that to then provide the sector energy and policy consumption data required.

The next slide. And then, the second piece here, what you can see here is the economic and demographic activity getting added, as well as the transportation energy demand models. So, once the historic data is fed to a sector energy model, the economic and demographic data, as well as the rate information is sent to both our transportation and energy models, our sector energy demand models, as well as use and self-generation models.

The next slide. And then the last piece as far as the inputs is the efficiency program. So, that's going to get sent exclusively to our sector models. And that is for, you know, specific end use adjustments that we will make that effect demand, depending on the type of efficiency measure. So, we take that information and include that into it. So, that will be things like efficiency standards, as well as programs in the state.

Perfect, next slide. So, from here another piece that we add there -- well, I guess after we've

produced all the -- after all the input information is set into our models, the models, you know, do their magic, produce their results, then that gets fed into a summary model. And from that point, you know, it's a process where we essentially just process the data. You know, taking in all the data from all the different models that we have, do some calibration where needed, and then make any final adjustments as well.

So, this is also important in our process where after we produce our baseline forecast, we could also incorporate AAE or additional achievable energy efficiency estimates to produce a set of managed forecasts.

Now, on my next slide you'll also see that, so prior to essentially -- prior to incorporating energy efficiency, we also send baseline consumption data to our hourly electric mode model, as well as our hourly load model, where they also get used to develop those forecasts. And those also receive input from the AAE process. And so, in that case it will be said hourly AAEE estimates to produce the managed hourly scenarios that we produce in our forecasts.

And then, once all that comes together you kind of get the full suite of forecasts as well, which you could see on the next slide. Yeah, basically, the piece

de resistance there. Once all that comes together and we've run our baseline forecasts, made our adjustments, sent that information to our HELM and hourly load models for these hourly results, incorporate the energy efficiency, and we end up with our data forecasting results.

So, slipping into the next slide, I just want to highlight, kind of go back a little bit and highlight that first part on model inputs here. And so, for this cycle, you know, this is just a little bit more detail on kind of what I just explained, specific to this year's forecast.

We'll have additional history that we can include in our forecast, the 2020 sales and consumption data. We'll also have some updated economic and demographic information, Moody's Analytics projects, the May vintage for 2021. And also, Department of Finance demographic projections.

Also, we'll learn more about this, this afternoon, but we'll also update our historical rate information, as well as assumptions for future rate impacts.

And then, lastly, we will have -- be incorporating the 2019 and 2020 efficiency programs, and Title 24 and Title 20 building and appliance standards.

And we also include some federal appliance standards as well.

And today, not listed here, because I think we're definitely going to be talking about them later, but we also have some updates for the AAEE and fuel substitutions that we'll learn more about later.

The next slide. But we have a few -- I want to spend a little bit of time on the updates to the self-generation forecast, it warrants additional planning, a pretty robust process. So, I want to highlight some of those updates here.

So, first, you have the inputs. So, we'll also be updating historic information for behind-the-meter PV capacity. So, we will include the 2020 capacity addition, then we also made some revisions to historical years which add, roughly, 150 megawatts to the history prior to 2019. And in 2020, we add about 1,400 megawatts of additional pass through. So that, you know, leaves us with a total of, you know, December of this past year to around 11,000 megawatts total capacity.

We're also going to make some updates to historic storage capacity as well. The key point here is that we're going to be changing, slightly changing up our data source. So, a difference from the last

forecast is that we will be relying fully on the interconnection dataset that we receive for both residential and nonresidential sectors, since we were able to complete the sector classification that that dataset requires. It's a more complete dataset, based on evaluation by staff. So, we feel more comfortable now using that, rather than relying on the extra dataset, which has already had some benefits in that the classification is -- was already handled. But it wasn't as completed based on staff's assessment. So, ultimately we've updated this. This update, as you can see there, a significant upward revision for the pre-2020 installed capacity. As I noted, because these are a more complete dataset.

So right now, you know, up to 2019 we have roughly 375 megawatts of storage capacity, behind-the-meter storage capacity, and we added about 200 megawatts in 2020 or so. So, now, we're roughly at about, you could say, 575 megawatts of storage capacity which is, you know, a 50 percent increase roughly. Maybe a little bit more, so in comparison.

The next slide. And here are a couple of the updates that we're planning for the self-generation model. So, first, many folks may know that, you know, the NEM proceeding opened up. But, unfortunately, this

was after our forecast from last year was already well established, or all the pieces were essentially in for that, so we weren't able to incorporate that.

But this year, you know, if there is a decision at some point, or a more clear direction, then we will be able to incorporate some type of, you know, NEM 3.0. Or, in light of that, in light of a clear decision we'll essentially have to come up with an idea of the range of uncertainty to build that into our assumptions, essentially, based on an evaluation of the proposals that are already out there. --

For context, if you look at our low case for PV adoption, it is more advantageous than a move to, you know, what some of the proposals are suggesting as far as a NEM 3.0 in the future. If that makes any sense. So, essentially, our low case looks better for PV adoption than NEM proposals that are coming out in this particular proceeding.

Another piece here is the federal tax credit, which is also something that we weren't able to bake in since that happened after our forecast was getting completed. But, you know, the tax credit was extended, so through 2023 so that could have a positive impact on self-generation adoption of PV adoption.

And lastly, another update here, for the

previous method of incorporating new PV due to Title 24 standards, essentially our method was accounting for new construction in residential, you know, sector housing had PV installed, but that home was not getting removed from that existing stock of homes that we viewed available in our other solar adoption model. So, we were modeling these things kind of separately.

And so what we're going to do here now, for this forecast, is integrate that modeling of new construction requirements directly into the model, so that way that eliminates any opportunity for, you know, double counting of existing stock. So, that filter should lead to a more accurate adoption forecast.

And then the next slide really just kind of summarizes, in a clear way, what we expect some of these changes to have -- what effects do we expect this to have on our self-generation forecast.

So, as I mentioned, you know, it appears that some of the NEM 3.0 scenarios don't look as beneficial to PV adoption as some of our scenarios, so that will likely -- you know, if we incorporate some type of forward-looking scenario around NEM 3.0, that would likely have a negative impact on PV adoption.

If we -- obviously, if we incorporate the extension of the tax credit, that's going to have a

positive impact. And then, incorporating the PV forecast for new homes directly into our PV model will also likely have a slightly negative impact on our forecast.

Go to the next slide. So, that's it for PV and self-generation, but I wanted to highlight a few of the other updates that we will be making.

So, household starts. This is a component that we use for our residential forecasting, as well as to inform our self-generation forecast that I mentioned.

So, previously, we had a method that inferred starts from overall household forecasts, but this was showing some inconsistencies with the historical permitting estimate. So, this year we're going to look at Moody's project for starts, for 2021 and, hopefully, we can rely on that since that appears -- you know, we need to do some further evaluation on that but it does appear to keep a little bit in mind of what some of the historical estimates are, and could produce, you know, a more reasonable result.

My other piece here is our commercial forecast. As you know, we have a commercial end use survey that we were hoping to get developed. But, obviously, you know, that's a survey actually going out to some of these buildings. And so, you know, that has obviously caused

a delay in getting that data. So, we're still a few months out from us to getting that. And it will be hard for us to say that we will be able to bake in any information into our forecast in time.

But one thing we do want to do, though, is in light of COVID really look at our assumptions around vacancy. And so, as you know, having more teleworking, you know, there might be areas where we want to look at, you know, office space and specific building task that we use to forecast to see if there is a way to, you know, based on the information that's out there come up with an estimate of what, if at all, our vacancy rate assumptions, you know, how they should be altered. So, that is something we definitely want to look at.

And then, lastly, agricultural sector. I kind of want to call out more cannabis forecast that we have. So, we definitely want to make some refinements with this. It's always kind of a struggle. The big part here is there's really a lack of historic data. You know, that leads to a significant uncertainty.

Essentially, we're having to, you know, estimate the history and then from that estimated history we also have to produce a regional forecast in the future. But, obviously, that causes a lot of issues.

There are some data sources that appear to be

coming out from, you know, the state's tax accounting of cannabis. But, obviously, you know, another facet to that is, well, you know, that only gets us the quote, I guess, non-illicit cannabis cultivation in the state. And, you know, that's just kind of a difficult area to get into where we have a sector or a process that was moving from, you know, an illicit area to now being legalized.

So, hopefully, we'll be getting more information and when more data comes out we'll be able to improve these estimates. But I just wanted to call that out. So, even for stakeholders if -- I know some of our utility stakeholders have also delved into these issues. So, we'd appreciate any information or ideas on how those utility stakeholders may be trying to forecast cannabis impacts in their territories. So, that would be very helpful for us to kind of bound some of these forecasts.

And so, I'll leave it there for our update. On our next slide I'm going to get into some of the economic and demographic assumptions.

We can advance one more slide there, too. But before I get into the assumptions themselves, I just wanted to discuss, you know, the basis for why we establish the assumptions ahead of our modeling work.

So, this morning I was mainly focusing on the net forecast overview and the assumptions there. But we have, you know, different -- you know, these different demand cases are actually just a part of a larger coordinated approach here. Not just for demand modeling but, you know, the system of modeling that we have.

So, this is electricity system modeling, like PLEXOS, that we're going to learn about more this afternoon, as well as modeling in the larger gap market.

And so, the whole basis is really, as I said, just to lay out these assumptions so that we can have a coordinated approach. You know, it simplifies just the transfer of data that we have between the different modeling that we do, and helps maintain a consistent analytical basis for those policy, and the questions, and analyses. Suddenly, you know, you're not going -- having a lot of confusion about, you know, what scenario goes where, or when assumptions change, you know, how does it -- is this assumption different from that one. We can really say that we're consistent in that way.

A little more on assumptions on the next slide. You know, the core metric nonetheless, as I mentioned, will not -- you know, our assumptions are more than just demand assumptions, but the core metric here really is a demand case. So, we try to organize those into three

different demand cases, and so the high demand and low that we use.

The mid demand case is going to be representing our, you know, likely outcome, you know, giving a set of baseline assumptions.

And then we have our high and low demand cases, which I call here as a range of uncertainty rather than, you know, more extreme outcomes that we could possibly model. So, that's what we're trying to do with these assumptions.

In the next slide, I call out the specific assumptions that we make. So, in the mid energy demand case, as I said these are our likely demand case assumptions. So, in here we have a baseline case for economic and demographic projections, impacts from climate change, electric vehicles, rates, as well as self-generation adoption.

Now, when we move to our high and low energy case, we make some changes there to better represent, you know, different economic outcomes, and a higher energy demand case in the case of -- as you see there.

So, in the high energy demand case we obviously higher economic and demographic projections, more accepted impacts from climate change, and then higher vehicle adoption. And the last two kind of slip people

up, but we also include lower energy rates, which would be -- at least in the short term would be consistent with a high energy case. You know, lower rates lead to higher consumption. But it's also lower rates also lead to lower self-generation adoption. So, that's why we have less self-generation there.

And the low energy demand case things are sort of flipped around. So, you know, the lower economic and demographic projections. In this case we don't assume any specific climate change impacts. We include lower electric vehicles. And then, in this case, once again where things are sort of a little different in that we have higher energy rates, which would be consistent with the lower energy demand case. But those higher rates also lead to making self-generation more advantageous, so that would be a higher self-generation adoption case as well.

The next slide. And here's just some specific information about the economic cases that we use for each of the demand cases, so economic scenarios. So, once again we're relying on Moody's for these drivers.

And so, for our high case we use a custom high scenario that was developed by Moody's analytics. And then, we use their prolonged lower growth scenario for our low energy demand case. And then, their baseline

scenario, or what they call a 50/50 scenario for the mid energy demand case.

And we are also using, as I said, demographic information from the Department of Finance. The one thing I wanted to point out here, you may remember that last year, you know, there was sort of an epidemiological sort of tint to the different economic scenarios and that is still the case here.

So, the assumptions for all three of these scenarios that you see at the top there do have that, you know, COVID sort of outlook, so to speak.

So, in the custom high scenario, for example, there basically is, in terms of vaccinations, very quick movement in terms of vaccinations and reaching herd immunity. So that scenario would essentially be, you know, no further restrictions due to COVID. You know, flights around the country are moving at a faster pace. Things are essentially fully open much faster.

Counter to that, we have that prolonged low growth scenario where, you know, vaccination doesn't reach herd immunity threshold as quick, and the economy essentially stagnates and stays in this low growth phase.

And the baseline scenario essentially, you know, splits the difference in that, you know, vaccination

moves along as scheduled and things kind of hurry along in terms of improving economy.

And so, the next slide just kind of gives a quick summary in terms of, you know, average annual growth rate, essentially the trend that's coming out of these different scenarios.

You'll see the drivers there on the left spelled out, along with our previous mid case, as well as our new mid case that we'll be using. And the high and low scenarios as well.

So, you know, there's a high degree, as I said, of uncertainty around these scenarios. But, you know, in the baseline case, as I mentioned, you know, we're hoping that -- the expectation is that herd immunity gets met, you know, relatively soon. It seems like, you know, in the news now we're somewhat there. There might be some hiccups, but it seems like a reasonable expectation that we could get there now.

But, you know, the difference here actually between our forecasts, you know, last year is we're no longer to forget 2020, we've kind of moved past that. But what we're really predicting now in these economic scenarios is, you know, the rate of recovery -- so, as you can see in the gross rates there, gross state product is a little bit improvement. Per capita income

does go down a little bit and I'll explain why in a second.

And then, the last piece there, as you can see, is that population and households are growing at about the same. But that doesn't quite tell the full story. You know, population estimates have been revised downwards and with that, you know, households, total households have both been revised downward. There have been down revisions to the historical data. And so, this ultimately leads to, as we look out to 2035, comparing what we would have forecasted last year to this year. We see reductions in population as well as total households. More so for households as we get out to 2035.

And for the next few slides, I'm just going to touch on briefly. I think I'm running a little short on time. Some of the GSP, some of the graphs, you know, charts for some of the data here.

Probably the take home message here, kind of looking at what I showed previously is GSP does look a little bit better. It recovered much sooner than we expected. And obviously, you know, federal efforts here really helped the economy. This is not something -- the recession that we experienced is not something similar to 2008 by any means. That was sort of a financial

meltdown, the financial crisis. So, we didn't really have that financial system collapse that required a bail out in this case. So, you know, once of the shutdowns started relaxing and people started getting back out there, you know, our economy is definitely -- you know, in terms of GSP things are recovering pretty quickly.

On the next slide I have statewide income, you know, per capita income. So, the big take home message here is that you can see there's a gap there between what our previous estimate was in that dashed line, for the mid case that we previously used versus what we have now. And so, that's really going to come down to government transfer payments, economic impact payments, and expanded unemployment programs. So, that's really boosting up the employment -- or per capita income figures that we have there.

But ultimately, in the long term you can see the growth is very similar, so that's really a change going on.

The next slide, looking at commercial employment. Obviously, we heard that there's some, you know, lingering supply constraints and there's some other things going on there. But ultimately, we do expect a recovery somewhat similar to what we were expecting previously. As I said, we were just kind of

getting out of predicting 2020 and moving on to, you know, looking at what the recovery is. So, we're no longer trying to predict how deep a valley we're going to sink into. We're looking at -- we know what that is now and we're just trying to look at the recovery here, in terms of the economics.

So, I call out a few points there. We still have quite a bit of jobs comparison to 2019 but, you know, the forecast is here to reach that 2019 level of employment by 2024.

But, obviously, you can see there's some differences here between 2008 recession recovery and, you know, it's a pretty robust employment growth coming out of that compared to a slightly -- you know, it is a kind of a quick recovery, but then the long term growth is a little bit slower looking at the forecast.

And so real quickly, let's jump to the last two slides that I have, or the last three.

So, I want to call out the comparison of electricity consumption. So, the graph here I can kind of explain. The blue line there represents historical electricity consumption from all sectors, so a total statewide electricity consumption in terms of gigawatt hours. And those gray periods are recession periods in our history based on, you know, declines, retractions in

GDP.

So, you can see there's a clear trend. If you can kind of focus your attention to the 1990s through about 2006 or 2007, a very clear upward trend there. And then after that period, you know, you see declines in consumption.

And so, there's a few things that could be leading to that trend. You know, it's never really just one thing, it's several factors. But it seems that, you know, obviously we had a sort of long, slow recovery coming out of the recession. Someone argued that took a decade to come out of that. You know, the efficiency standards really, in 2006, post that period are really going on, we had a lot of market transformation in terms of LED light bulbs and things like that. And also, you know, electricity rates were also increasing quite a bit.

And then, adding to that we know, as I mentioned, you know, population growth estimates have been going down. So, that's really what was happening there.

In terms of like 2020, there really wasn't a whole lot of -- well, I'll talk about that in the next slide.

I just want to jump to the stored gas

consumption. You know, it's a little more volatile, some of the gas consumption as I mention -- as I mention here, you know, industrial sector is a large user of the gas. So, in terms of end use gas -- well, let me make that note here. So I'm not -- sometimes people use total gas consumption in two different ways. But when we talk about end use gas consumption what we're talking about is gas consumption not include gas that would be used for electricity generation. So, that's why you might see the usage figures be a little different depending on how people look at that.

But in terms of end use gas, you know, industrial sector is one of the largest users, with residential coming shortly behind it.

But you can see here, you know, there's a trend downward after -- well, there's some clear linkages between recessions and gas usage, but there's also a trend downward that you can see after the late 1990s, early 2000s.

And so what's really happening here, from looking at the data, is it appears that, you know, residential demand has been trending downward while nonresidential, you know, that industrial gas is relatively flat. And so, we can also attribute this to some efficiency that's going on. And, you know, the

industrial sector in general, in California, has been relatively flat or even declining a bit. So, that seems to be the two causes in these trends here.

And then on the last side that I have, regarding this history and some recession impacts, you know, you can look at -- you know, looking at the historical data, first of all I haven't weather normalized these. We'll need to do that to get a true sense. But just looking at the raw history and comparing 2019 to 2020, pretty modest increase in -- decrease in consumption, about one and a half percent compared to 2019.

And for the large decrease here, really just the nonresidential consumption, you know, a lot of the COVID impacts there. People weren't able to go out to restaurants and different industries that were affected in many ways.

But on the flip side of that, you know, that decrease in demand was, you know, offset by increased residential consumption as people were in their homes.

On the end use gas side of things, a larger decrease. Once again not weather normalized, but that was about a 5 percent decrease looking at 2020 versus 2019. And this is mostly driven by nonresidential as it appears there really wasn't much change to residential consumption in the history.

And one thing I wanted to point out, I was actually looking at this data earlier this morning, you know, our electricity forecast and our consumption forecast, that's what I was comparing this morning, and we're actually looking at 2020, you know, in aggregate statewide. Our forecasts ended up being only about a half a percent off. We were a little lower than what the expectation was, but we were pretty close in terms of estimating 2020 given the data that we had, and all the various uncertainties that we were working with.

So, hopefully, that leads to some additional confidence in our forecasting work as the Commissioners highlighted this morning.

And then my last slide here, just kind of goes into some of the next steps. We're going to try to finalize some of these demand updates, these model updates. We appreciate any feedback or comments from stakeholders, particularly our utility stakeholders.

And then, once again, we'll try to get the draft results out a little bit earlier than we normally do, so we can be well prepared for our final workshop and get this forecast adopted in January of next year.

So, I think that's my cue for time. I think I was -- felt like I was right on time. So, I just want to thank you and open it up to any questions from the

dais or the public.

COMMISSIONER MCALLISTER: Thanks Cary. Thanks for that presentation. I do not have any specific questions. It's good to see some of the initial, some of the work that you've done on sort of the 2020 issues and putting those in some context for the longer term. But good to be turning our attention towards kind of the future structural issues.

Any questions from anyone else on the dais? Yeah, go ahead, Commissioner Monahan.

COMMISSIONER MONAHAN: Cary, I wonder if you could elaborate on how the more recent trends in terms of wildfires disrupting, and maybe this is different from the demand forecast per see, but you know with higher temperatures and fires kind of disrupting some of our generation capacity how does that fit into -- do our demand forecasts kind of take into consideration or weight more heavily these newer trends that we're seeing in terms of higher temperatures, and just more grid stress?

MR. GARCIA: Yeah, that's actually a good question for our next presenter. Nick is actually going to get into specific temperature trends. So, he can probably elaborate a little bit. Like you said, we're focused on the demand side of things. So, thinking

about wildfires, right, that could -- if we move into the space where we want to, you know, start modeling what effects, you know, cloud, you know, smoke and things like that have where you've seen that on the supply side of things, with utility scale solar, where there's like some wiggliness in the output from those things. You know, it seems reasonable that that can be investigated as far as what impact that has on -- you know, on the behind-the-meter side of it, all the rooftop solar that's out there. And possibly taking that into account during, you know, those sort of peak events, right, because that could be an additional peak that would add additional demand if there's, as you say extreme heat, and no self-generating electricity, right, you'd say that, oh, yeah, that should lead to a higher demand outcome.

But yeah, I think that's definitely a good question I think for Nick. And, hopefully, I think he'll --

COMMISSIONER MONAHAN: And one more question. I mean, COVID was such a strange time, right, where we had all these buildings that were empty, but you still had to provide basic services to those buildings. So there was some, you know, basically load happening even though there weren't very many people in the buildings because

the few people that were needed heat or cooling.

MR. GARCIA: Yes.

COMMISSIONER MONAHAN: Are there any scenarios that we're thinking about in terms of sort of a more disruptive view of work from home being more dominant and, you know, like we're doing with the Energy Commission which is downsizing, and assuming more people are going to work from home. Many businesses are starting to do that in a more permanent way, which would allow for energy use reduction at the facility itself, instead of this kind of inefficient use of energy that we encountered during COVID.

But are we looking at any scenarios on that front where sort of a mass, more of a major shift to work from home?

MR. GARCIA: I mean we could. So, that's why I mentioned, you know, the investigation of our vacancy rate to the commercial sector. So, we have, you know, various buildings in there. The first ones that come to mind are, you know, offices. So, you have like small office, large offices. So, we know that people can't be at two places at once, right. So, if they're working from home, then they're not going to be in an office.

And so, what we really want -- what I'm thinking of, planning on doing is basically, you know, we have to

investigate this, we essentially have to run the model, you know, a couple times to get a sense of, you know, let's just hold our baseline assumption the way it is, and then let's look at these different scenarios where we adjust the vacancy rate assumption. So, you know, a small office based on -- the difficult part is, you know, we're trying to figure out, you know, what exactly that is. There's some limited surveys out there that we're looking at right now, that kind of give a general sense of what, you know, business owners are thinking in terms of how utilized their spaces will be. Will that be a temporary -- you know, maybe for a couple of years that might happen and then, you know, further on they'll want to build it out.

On the flip side of that you may have less space, but some of those surveys are saying, well, when I have people there I'm going to have more space with less people, but then I'm going to build up some of the services that I may have there. So, you might have it, you know, more air flow which, to me, thinks about you might have more air conditioning. You might have more general, what would you call it, comfort in your facility.

So, that might be getting a little bit too in the weeds on these assumptions. But all I have to say

is that, yes, we are going to try and look at some of these, what these surveys are saying as far as what the vacancy looks like. And then, test that to get a sense of what is a range of possible outcomes. But ultimately, we do need to, you know, set up a baseline forecast that shows those things.

That's another space where it would be helpful to get feedback from stakeholders, the utilities as well, to get a sense of what they're thinking as far as -- well, what they're hearing on the ground as far as what their asking --

COMMISSIONER MONAHAN: All right, thank you.

COMMISSIONER GUNDA: Commissioner McAllister, just one quick kind of comment and then a kind of a possibly question. And I think just responding to Commissioner Monahan, you raised a number of issues I think that we're trying to grapple with on this, which is you specifically pointed out to that end of the uncertainty created by changing behavior. And I think there is this constant, not tension, but kind of a balance between, you know, what is a reasonable forecast that we plan resource procurement on that then is kind of like, you know, rate based. Versus how do you think of these uncertainties and how do you bake them in.

So, there are a few other conversations that are

happening and I think on the uncertainties, and I'm really glad that you're raising that. And that's definitely of interest for the team to think through.

So, thank you. Thank you for raising that and that's very important.

On the question side, I think you, again teeing off of your question, Cary could you comment on specifically the econ demo assumptions on -- so, we had a couple of waves of COVID last year, and then we had another one this year. Do we anticipate another wave? I mean looking at the current situation on vaccinations.

And would that be taken into account in the short term or it's not a focus on the work of IEPR this year?

MR. GARCIA: No, that is taken into account. So, I tried to mention that. So, in the baseline scenario that we're getting from Moody-- I think that specific assumption right now -- obviously, you know, every time we get forecast information, it feels like the second you get it, it's out of date.

So, in the -- looking back at the assumptions for that baseline scenario, and what they're essentially saying is that we reach our herd immunity level, I think they were say by mid to late July.

And so, we know now that we're probably not quite there. I think as far as by now, on the latest information. But I think we're close. You can question, you know, what exactly is herd immunity, that's another question.

But the high scenario, for example, assumes that we've already reached that herd immunity much faster, and we're there already, and things open up and we go back to normal.

Like I said that mid case assumes, you know, right around now, you know, we're getting to that point.

And then, our low scenario essentially says that is delayed for another year. So, I think it's held like quarter one of 2021, by the early part of 2021 we'll get to that immunity.

And if you look at some of the graphs, you can see there's this sort of big gap on the bottom in comparison to the highest case. And it's really getting to that, you know, there's a lot of down side lists there. So, as things still improve, you know, things could -- I don't want to be too dramatic but, you know, things could get sideways. But, you know, things could always, you know, look -- not look as good as acceptance here, you know, right. Positions are still pretty, I feel like fluid.

And then, you know, what's the big piece there, too, how does employment recover. You saw there was quite a bit gap there. GSP, income, those parameters look pretty reasonable, but like getting people back to work, you know, economically like that seems like another big risk. You know, what does the economy do when you have a large amount of unemployment.

COMMISSIONER GUNDA: Thank you, Cary.

COMMISSIONER MCALLISTER: Shall we move on to Nick for the weather piece.

MS. RAITT: Yes, please. Go ahead, Nick.

COMMISSIONER MCALLISTER: Great. Thanks.

MR. FUGATE: Thank you. So, good morning everyone. I'm Nick Fugate with the CEC's forecasting team and I've prepared a brief presentation on historical weather.

This is not a topic we typically discussion at our inputs and assumptions workshop, but given the extreme heat events in the last summer it certainly seems it's worthwhile to review the role that weather plays in our forecast process.

The next slide, please. Now, while humidity and cloud cover are inputs to our hourly load models, temperature plays the most varied and impactful role in our modeling. And so, that will be the focus of my

presentation.

There are a few key statistics that we track. The first is max631. This statistic is a weighted average of maximum daily temperatures across 3 consecutive days, that is 60 percent of the current day's maximum, plus 30 percent of the previous day's max, plus 10 percent of the max from 2 days prior.

And this is a useful statistic for capturing the duration of a heat event which can affect how people respond to it.

We also pay attention to daily minimum temperature as, again, people respond to a hot day differently depending on how cool the previous evening was.

And we also tracking heating and cooling degree days, which are a measure of how hot or cool the temperature was over one or more days. This is measured in relation to some fixed thresholds. We use 65 degrees to represent a comfortable temperature requiring little to no heating or cooling. So, when the data hits 85 degrees, it would translate to 20 cooling degree days, 8 minus 65. And the data reaching only 50 degrees would represent 15 heating degree days.

And these statistics can be summed over an entire year, giving an indication as to whether that

year was particularly warm or cool, which in turn indicates whether loads for that year have unusually high or low levels of space conditioning loads.

And that's actually one of the main uses for these statistics, weather normalizing peak and annual energy demand in a base year. Max631 and minimum temperatures are used for normalizing peak loads. And heating and cooling degree days are used for normalizing annual consumption. And this is an important step since the base year is the starting point for our forecast. If it happens to be really hot and we don't normalize that load, then our entire forecast would reflect an unusually high level of cooling load.

We also use the distribution of maximum and minimum temperatures to determine not just what peak load would be under normal peak load conditions, but also what peak load would be under more extreme conditions, like those that you would expect only once every five years. We call that our 1-in-5 forecast. And then, once every ten years, or 1-in-10, and once every 20 years.

We use these four statistics, max631, min heating and cooling degree days as inputs to our econometric peak and sector models. These are the same models that we use to estimate climate change impacts,

as we run the models once using average historical temperatures as the baseline, then again using gradual temperature increases projected by climate models as part of the California's 4th climate assessment.

The next slide, please. Of these use cases, our peak load normalization process is especially important as it is closely tied to our year ahead forecast, which is used as a system level benchmark for resource adequacy.

To review, we employ a three-step process. First, we specify an econometric model which predicts daily peak load as a response to daily max631 and minimum temperatures. We estimate that model using the most recent three years of load and temperature data.

And then, once we have modeled the present day load response to temperature, we estimate daily peak loads using historical temperature data collected over the last 30 years. This gives us an estimate of what present day loads might have looked like had we experienced a summer similar to each of the past 30.

And as a final step, we look at those 30 simulated summers and we take the peak simulated load from each. That gives us a distribution of peaks from which we can draw a median value, or a 1-in-2 weather normalized estimate for the base year peak.

And using that same distribution, we can also examine the relationship between a 1-in-2 load event, and other more extreme events, 1-in-5, 1-in-10. And then we develop scale factors that we apply to our 1-in-2 peak forecast in order to create the other weather variants.

The next slide, please. So, given that we are using a 30-year rolling window of historical weather patterns to assess what is normal, it's worth taking a look at that distribution. Here I've graphed daily max631 for every year of the last 30 years.

This is actually a typo in my slide here. The historical series dates back to 1991, not 1985. So, I'm showing the same 30-year window that we used for normalization.

I'm using a single statistic meant to reflect temperature across -- temperatures across the entire CAISO control area, which is -- it's not a statistic that we used in our analysis, but it's helpful for illustration, although the temperatures I show in this presentation are a weighted average across the CAISO control area.

Now, the thing that's immediately striking here is that the two most extreme events occurred within the last four years. And both 2017 and 2020, in early

September saw extreme temperatures several degrees higher than the next highest event, which occurred in 2006. And as an aside, I remember that 2006 summer quite vividly. I'd just moved to Sacramento from the Bay Area, and there was that two-week stretch of 100-degree weather. And I remember thinking there's no way I'm going to be able to live here.

But a quick update, though, on that point, I actually really like it.

The next slide. So, to clarify things a bit, I've taken just the peak value from each series in the previous slide and plotted them here. Note that for this plot I have gone back to 1985, and mainly to show that after the 2017 and 2020 extremes, the next highest values date back to 1985 and 1988. My personal recollection for those years is not nearly as strong, but anyway.

This is what we use a 30-year period -- this is why we use a 30-year period, so that our historical record captures these extreme events that occur infrequently.

It's also interesting to note the apparent decadal pattern periods of consecutive cool years followed by consecutive warm years, repeating every ten years or so. This would perhaps make me hesitate to

expand or truncate the historical window in anything other than ten-year increments.

The next slide. So, here's the same chart but for peak minimum temperatures from each year. While a increase in minimum temperature does not elicit the same load response as an increase in max631, it is an impactful statistic. And with minimum, there appears to be a more pronounced warming trend. You can see that within the last ten years there are no values more than a degree below average. This stands in contrast to the 20 years prior, where half the values are a degree or more below average. And then, similarly, the above average values are pretty concentrated in the last ten years.

The next slide. And this pattern holds as well when you look at all daily temperatures, not just the annual peaks. Here I'm showing the distribution of daily max631 and daily minimum over the last five years in blue. And that's versus the distribution over the entire 30-year, previous 30-year window in red.

And I know I'm already breaking my rule about not truncating a series mid-decade, but that's what happens when I prepare my speaking notes after I've already docketed my slide deck. I did take a second look at this using the last 10 years versus the last 30,

and the pattern is similar.

So, for max631 the most frequent temperatures occur in a similar range across both distributions, but extreme values are more frequent in the last ten years. And for minimum, the last ten years shows a general upward shift in the entire distribution.

While I'm not proposing here today any adjustment to our normalization process, I do think it is worth some stakeholder discussion around this question. Does this upward trend warrant an adjustment and, if so what would a reasonable adjustment look like.

So, this is a question I intend to raise with DAWG next month, before we begin our normalization process.

The next slide, please. And the last point I want to make is that we might expect a change to our 1-in-x multipliers just as a consequence of adding 2020 to the historical series. What I'm showing here are the 50th, 80th, 90th and 95th percentiles from the two distributions of max631.

The first spans 1990 to 2019, that's the red one. And the second covers 1991 to 2020, in blue. So, two 30-year windows that almost completely overlap, except one includes 1990 and the other includes 2020.

And you can see that the extreme events of last

summer does very little to impact the 1-in-2. But the more extreme values see a notable increase. After adding 2020, for example the 1-in-5 actually ends up looking more like the 1-in-10 from the prior distribution.

The next slide. And so, as I alluded to earlier, we are planning a DAWG meeting in September to discuss a number of things, but in part our weatherization process. Cary had a link to this in his earlier presentation. But if you just Google Demand Analysis Working Group you'll be able to find our CEC webpage that has a calendar of meetings, as well as a listserve you can join to be notified of future meetings, if you are interested in participating in that discussion.

And then, in early October we will receive the last of this summer's load data, and that's typically when we begin our normalization analysis. We do try to use the most recent summer's weather data in this process.

And then, as a longer term activity, this is beyond the scope of the current IEPR, we are engaged with our Energy Research Division as they embark on the next climate assessment. This work promises to yield some rich datasets, both in terms of historical weather

data and also climate modeling results. So, this will allow us to refresh our climate change estimates and, hopefully, expand the analysis to examine not just average temperature increases, but also the frequency and magnitude of extreme temperature events over the entire duration of our forecast horizon.

And that's what I have prepared, so I'll pause here and turn things over to the virtual dais.

COMMISSIONER MCALLISTER: Thanks Nick. I think I -- maybe it's a little bit of bias on my part, but I think even on the 631 slide it looks like there's an upward trend over time, over 30 years. I wonder if you could maybe show us that and see what the statistics might tell us about that. You know, it's more variable and there are more below average years as well, but it seems like there's a trend upward on that one as well, maybe not quite so clearly as the --

MR. FUGATE: Yeah, I certainly agree. It just is not as pronounced as the minimum, but it does, the same trend appears to exist there as well.

COMMISSIONER MCALLISTER: It seems like maybe that's the issue there really is just variability. I mean that's the nature of climate change is that, you know, the extremes get more extreme whether they're above or below, but they still tend to trend upward.

But, you know, I don't know if you want to comment on the challenge of capturing that variability just per se?

MR. FUGATE: Yeah, the challenge is, you know, our process is so dependent on historical data, it is difficult to -- you know, based on 30 years -- I mean you can incorporate that kind of trend to the average temperature increases over 30 years, but that doesn't get necessarily at the variability question.

And that's why we are, you know, hopeful for this work with the RDD and all of the consultants working on climate modeling, because I think that really promises to give us the most insight and, you know, what variability might look like based on the modeling results, as opposed to just being dependent on, you know, historical temperatures.

COMMISSIONER MCALLISTER: Yeah. Does anyone else, Commissioners Gunda, Monahan, anyone else have a question? Go ahead, Commissioner Gunda.

COMMISSIONER GUNDA: Yeah, thank you, Commissioner McAllister. Nick, thanks to you. I think this is a really, really good presentation. I think this is not something that at least I historically would missed where we talk through trends and how we're thinking about modeling moving forward. This is extremely helpful framing to just kind of understand at

a 30,000-foot level, you know, some of the trends and how do we then make sure those trends are captured. So, I just want to give you kudos for kind of setting this up.

So, a couple of questions and then maybe comments. And the first thing I think for me that kind of stood out is really the minimum temperature slide that you put together. So, I mean as we are trying to work with the reliability issues over the last, you know, 12 months, one of the key indicator in the day-ahead forecast and the swing that the CAISO does is really the minimum temperature. And how much cooling happens overnight really dictates how far off the next day we are.

A couple of questions there. One is how much do we capture the minimum today in our forecasting? Like, you know, I know we use the 631 statistic in the regression modeling, I believe, maybe I'm not accurate here. Can you just explain how much weight the consecutive minimums play into our modeling today?

MR. FUGATE: So, the minimum does play a role in the regression as well that we use for the weather normalization. It is not weighted as heavily as max631. My recollection of how the coefficients shook out last time is that -- and it varies a little bit by TAC area

but, you know, you might expect like a 70/30 weighting for, you know, 70 percent max631 and 30 percent minimum.

COMMISSIONER GUNDA: Okay. So, yeah, I think I would really like us to potentially have, you know we'll have a follow-up conversation on this. But I think this is helpful to think through what additional statistics we might want to consider moving forward in terms of thinking through the development of the forecast.

The kind of the second question I have is, you know, you kind of talked about the periods that you were able to do this analysis, we have 35 years of data. You know, if we went further back or, you know, if you take the last 5 years versus the last 10 years, and so on what is your kind of high level vision as a modeling expert here on how do we consider whether moving forward? I mean, do you have any high level thoughts that you're already thinking through?

MR. FUGATE: Well, it does seem -- so, you know, we have a few different things that we're doing that all kind of interact, right. We have our climate change estimates that we include in the forecast, but those are kind of incremental to the base year. So, one of the things that is on my mind is that it's important that, you know, our weather normal estimate of peak load also kind of consistently reflect -- or reflect, you know,

that climate change trend that we're considering in the forecast in a consistent fashion. So, that is one of the things that, you know, I think that we may need a little more work to, you know, maybe integrate some of the same sort of adjustments that we are making on the forecast side with the weather normalization piece. So that, you know, when we have those climate changes of increment to the base year that, you know, it's consistent with what we're doing in the weather normalization process.

I hesitate to -- I know some other forecasting groups use fewer historical years to, you know, determine what is normal. I hesitate to do that just again because, you know, you risk losing some of the variability. But, you know, that might -- that might -- our assessment of that might change as we, depending on what sort of data comes out of some of this climate modeling work that we'll be doing in the near future. So, to the extent that can supplement or address some of the questions we have about variability, you know, it could be that we don't need as many historical years to really get at the variability issue.

So, the last question then I'm going to turn it over. You kind of mentioned other atmospheric variables like humidity, or smoke cover, and such and how that

impacts the demand forecast. I mean taking into account fires are becoming more and more common, and do you have any high level information that you want to share into, you know, what are we talking about in terms of impact? Like, you know, if humidity were to increase, I don't even know to think about it, 10 percent, 15 percent it drops, or smoke goes up or down are we -- you know, what impact does that have, you know, on our forecast overall?

MR. FUGATE: I haven't thought as much about the humidity question, but I do think the -- you know, possibly the wildfire question could be pretty impactful. You know, if we have periods where we have, you know, a significant amount of smoke cover over large areas, you know to the extent that that impacts our behind-the-meter solar generation, you know, that may need to be accounted for.

In the historical series that we are using to do things like estimate our hourly model and to estimate, you know, what sort of counter factual peak load events. So like for example right now, and this may -- hopefully, this gets a little bit of a Commission on-hands question, but to the extent that we have service outages, to the extent that we have, you know, sudden drops in PV, behind-the-meter PV generation due to

wildfires, due to public safety power shutoff events, due to all these different things that are happening, you know, we need to have some way to reconstitute that historical load to have an idea of, you know, what would consumer demand have been absent these sort of events that we're not taking into our forecast.

I hope that addresses your question.

COMMISSIONER GUNDA: Yeah, that does. Thank you and look forward to engaging with you, Nick. And again, kudos to the entire team for tackling these complicated issues, so thank you.

COMMISSIONER MCALLISTER: Agreed. Thanks, Commissioner Gunda.

I think we're a little bit over time, so unless there are other questions --

COMMISSIONER MONAHAN: I do, I have one -- I have one more question.

COMMISSIONER MCALLISTER: Oh, sorry. Go ahead, Commissioner Monahan.

COMMISSIONER MONAHAN: Heather said it was okay, I've been chatting on the side --

COMMISSIONER MCALLISTER: Oh, sure.

COMMISSIONER MONAHAN: -- to make sure it was okay to ask a question.

So, Nick, I wonder, as the one least steeped on

the dais with these issues, can you tell me if I'm getting it right that what you're doing right now is collecting input into how to weight these different time variables, and that it's not clear at this point how the demand forecast is going to weight the minimum peak or the maximum peak in terms of the historical, you know, perspective. Is that fair to say you're collecting input on this?

MR. FUGATE: Yeah, I would say that that is a reasonable summary of the question kind of that we want to take up with stakeholders in the --

COMMISSIONER MONAHAN: Uh-hum.

MR. FUGATE: -- in the coming months.

COMMISSIONER MONAHAN: And could you envision a scenario where we looked at or we weighted like the last decade more heavily? Well, I think especially when it comes to minimum peak, as Commissioner Gunda was saying. I mean there's some data that would indicate that would be appropriate. It's a little bit more complicated with the maximum peak. But could we have a scenario where we looked at more recent data?

I mean I think you gave the personal example. We all have personal examples of how it has gotten much hotter in California. And I will say living in the Bay Area never used air conditioning and we're thinking

about getting air conditioning. We're think about, you know, because of smoke people are keeping their windows closed, they're not opening their windows, and so there's more need for using electricity and cooling, whereas we might have just opened our windows at night in past days. And so, you can envision these kind of, I don't know I want to call them doomsday, but these more grim scenarios going forward where there's just a lot more electricity, especially air conditioning being used where, as you said there's less solar being generated, and where temperatures are getting higher and higher.

MR. FUGATE: Yes, I could certainly see sort of arriving at a kind of adjustment into our process that it takes -- that weights more heavily than the recent years, recent historical years just to get at this -- exactly this issue you're describing.

COMMISSIONER MCALLISTER: Can I ask a sort of correlated question alongside, maybe I think it's similar enough. Are you -- do you sort of periodically evaluate whether that 65 degree pivot point is still the appropriate pivot point for above which you have a cooling degree day? I mean it may well be that as the trend goes hotter maybe that pivot point increases or changes in some way.

MR. FUGATE: I don't know what the last -- I

can't recall the last time that we evaluated that pivot point. I mean it's a reasonable point. And actually, in discussions with just one of our staff recently, who was looking at natural gas normalization, weather normalization, suggested that perhaps 68 degrees was a better threshold.

So, I think it's definitely worth, you know, taking a look at, sort of periodically reevaluating. But we haven't done it --

COMMISSIONER MCALLISTER: I think the regression ought to -- it ought to be fairly straight forward to set up a regression to see what that seasonal energy consumption, that summer, seasonally-based energy consumption is and sort of do a best fit to that to figure out what the pivot point is, which temperature.

MR. FUGATE: Yeah.

COMMISSIONER MCALLISTER: You know, I think that's a fairly standard -- but anyway, I didn't want to distract from your answering of Commissioner Monahan's question. Sorry.

MS. RAITT: This is Heather, do we feel like --

COMMISSIONER MONAHAN: I think I'm done.

MS. RAITT: Okay.

COMMISSIONER MCALLISTER: Okay, great. Great.

MS. RAITT: We're a little behind schedule, so

if it's okay we'll move on to Ingrid's presentation.

COMMISSIONER MCALLISTER: Yeah, please. Please, Heather, go ahead.

MS. RAITT: Okay, great. Great.

COMMISSIONER MCALLISTER: Ingrid, go ahead.

MS. RAITT: Next is Ingrid Neumann and she's the Technical Lead on Building Decarbonization in the Energy Commission's Demand Analysis Office. Go ahead, Ingrid.

MS. NEUMANN: All right, so I've been introduced. And I'll be taking today about additional achievable energy efficiency, which is a load modifier that we've been applying to the baseline demand forecast for about 10 years. And then, about a new load modifier that we're on towards fuel substitution.

The next slide, please. So, Energy Assessments Division has various decarbonization analysis projects that we've been working on and we'll also be reporting in the 2021 IEPR. We have our Energy Efficiency tracking and projects. The tracking is in response to SB 350, so we've had that on the bottom bar there in blue. It starts with a base year in 2015 and goes through the end of 2029.

Then, we recently added some building electrification what if scenarios as part of our work to support AB 3232.

And like I mentioned at first, we have the Additional Achievable Energy forecast that forecasts additional achievable energy efficiency projected by various programs from the IOUs and POUs, and so on.

Those are layered on top of the baseline forecast, so those are incremental to the baseline forecast. So, since our forecast for the 2021 IEPR will be looking at years from 2022 through 2035, so will our AAEE.

So, the AAEE is that extra bit of energy savings that's not as certain as what's forecast in the baseline consumption. And so, that means that there are natural gas decrements, as well as electricity decrements there.

So, if we're looking at adding an electrification load modifier to the IEPR forecast that will be a little bit different, though we are trying to develop it along the same kind of basic methodology as we've used for AAEE the past ten years.

So, what's different is that any time we displace gas use, right, we'll actually be adding electricity consumption.

Then as Matt mentioned earlier today, we're also working on long-term demand scenarios. You can see the bottom bar extends to mid-century. And these are supposed to be able to help us look at some future

policy goals towards mid-century climate goals. So, this is different than the AB 3232 and the SB 350 that are ending more in the near future, and also different than what goes into the actual demand forecast.

All right, let's move on and focus on those items, the AAEE and the electrification load modifier. So, next slide, please.

So, for additional achievable energy efficiency, let's go to the next slide. We have the single managed forecast set, and I took a quote from it there when it was established in 2013. It was memorialized in every IEPR since then. When it was first established, the baseline cases of low, mid and high that Cary discussed were part of that, as well as five scenarios of AAEE. So, ones ranging from conservative energy efficiency assumptions all the way to something that would be more aggressive or optimistic.

More recently, we've had six scenarios there in support of the very aggressive energy efficiency doubling goals set by SB 350. So, in 2019, as well as in 2017 we had six different variations of future possibilities for energy efficiency reflected there.

So, what's also part of this single managed forecast set is how which scenarios will be used. So, the Joint Agencies, those being the CPUC, the Energy

Commission, CAISO, and CARB have agreed to use the mid-mid-AAEE forecast scenario for systemwide flexibility studies, which are relied on for procurement and transmission planning purposes.

So, as the name implies, it's basically been our scenario three, if we start from the most conservative scenario with number one going all the way to the most aggressive ones being five and six. So, we're using that mid-mid as our business as usual or our most probable future for that forecast.

So then, because of the local nature of reliability needs and the difficulty of forecasting locally disaggregated AAEE, the low-mid-AAEE scenario is used for local studies. So, that ends up being numerically AAEE 2.

So, the next slide, please. So, we're working on updating the tools that we developed towards our work in 2019 and, of course, also updating the data sources as those have come in this spring. And then, more recently in the summer as well.

So, there are three large data sources that we start with. The first one being the CMUA Potential and Goals Study. So, those contain the POU projections. So, from the utilities, what they think their energy efficiency savings will be for the future years.

So, they do this update every four years, which means that this time we can use the 2021 version that they submitted in the spring.

Then we also use the CPUC's Potential and Goals Study, which will contain various scenarios, one which is chosen as the goals for the IOUs' potential programs. So, we use that for the IOU projections.

Then we have our own set of Beyond Utility Workbooks which contain programs that save energy in the State of California that are working outside of the utilities, whether they're IOUs or POUs, or that are just not captured in those Potential and Goals Studies.

So, sometimes there is some overlap there. Most importantly in the Codes and Standards we have those captured in our Beyond Utility Workbooks, and we've been doing a lot of work there in improving those. Right, because Codes and Standards include Title 24, the Building Standards which are developed by the Efficiency Division here at the Energy Commission, as well as the Title 20 Appliance Standards that are also developed in the Efficiency Division. They also include Federal Appliance Standards.

So, sometimes with those Codes and Standards there are some overlaps with savings in our Beyond Utility Programs, and those in the Potential and Goals

Study, so that's why there's that up and down arrow there. And we make sure that we don't count any savings more than once. We want to count them exactly once, capture that, but also not over count.

So then we take all those first year projects and in our tool we roll them out to make them cumulative projections for the forecast period.

So, here we're showing 2020 to 2030. You know, for this 2021 update we'll be looking at 2022 to 2035. So, we end up getting total energy efficiency savings projections by year for a utility, or we are also able to do it by forecast zone, sector, end use, and then for the six different scenarios.

We then run this through an hourly tool, match those up to end use load shapes and are able to give 8760 hourly savings values for the entire forecast period.

The next slide, please. So, you're not intended to read this entire chart. I guess we don't need glasses, if we can. But really, what you're supposed to get out of this is the complexity of what goes into the scenario development.

So, we have those three data sources and I kind of separated out the Codes and Standards as being their own beast, because they're not incentive programs or

anything like that, right. So, and they have that unique overlap so we treat them a little bit differently, and more carefully.

So, we have those four sort of data sources. And then, what you can see on the right-hand side are six different columns, which are specifying each of those AAEE scenarios as they were developed in 2019. We'll be doing the same kind of thing again this cycle.

Then you see many rows, and those calls out specific savings elements coming from those data streams, as well as variation on those elements that we can apply to make scenarios more conservative or more aggressive.

Like for example we could have, you know, more conservative compliance rates applied to Building Standards, for example, or we could have higher incentive amounts, you know, greater funding for some of the program savings. And that can allow for some of that variation. Of course, we can also just include some measures and not include other measures, if those will be phased in, in the future.

So, the next slide, please. So, what we're proposing for the 2021 AAEE is doing the same type of methodology, so using the same savings accounting, aggregation and extrapolation methodology and tools as

were developed for the 2019 cycle.

And then, we'll be adding some new bells and whistles. We will have hourly GHG savings from gas and electric energy efficiency, instead of an annual roll up. So, we'll be able to report those as well.

And then, we're extrapolating the savings out past the traditional forecast period. Won't use those for the demand forecast, per se, but we'll be using those for these long-term demand scenarios and have that capability.

We've also, you know, included more historical data as that's come in over the past two years. As I've mentioned, the potential savings program projections from POUs and IOUs are being updated. And then, some of our own Beyond Utility Workbooks are being removed or added to as we have received updates on recent programmatic activities.

The next slide, please. So, moving on to our new product. We are proposing to add fuel substitution as an annual and hourly load modifier to the demand forecast, in a way very similar to how we treat AAEE currently. And we've called it, then, Additional Achievable Fuel Substitution, or AAFS.

The next slide, please. So, first we did include some fuel substitution in the 2019 IEPR. And we

did this, it was captured within AAEE as one of our Beyond Utility Workbooks. And what it was is it included a what-if, you know, a speculative percentage of all-electric new construction. And we started with an assumption of, you know, well, what if all-electric new buildings are half a percent of all new buildings built in 2020. And in 2030 we're at five and a half percent. And we ramped that up linearly for the low cast. And that's in light blue here because AAEE scenario 2 was used for local capacity planning.

Now, in the more teal color here, the mid-AAEE 3 is shown as starting at one and a half percent per year, beginning in 2020. And that ramped up linearly to a cumulative value of 16 and a half percent of new construction being assumed to be all-electric.

So, this time we're trying to take a more firm approach to what kind of programmatic efforts have been developed, as well as our work here at the Energy Commission in the 2022 Title 24 standards.

So, the next slide, please. Ah, but we did a lot of work since then, right. So, what work as EAD done since the 2019 IEPR in the scope of fuel substitution? So, we did develop a Fuel Substitution Scenario Analysis Tool, and we used this FSSAT to analyze building electrification scenarios to support

our AB 3232 analysis, which is going to a business meeting for adoption next week.

So, each of the electrification scenarios that we developed that met or exceeded that 40 percent GHG reduction goal by the end of 2029, which is set by AB 3232, that's that target, they actually have substantial incremental electric energy added by that time, due to the electrification efforts.

So, in addition to then increasing the peak loads, we actually found in our work that electrification can shift the dates and the times of those peaks.

So, that occurred in Northern California in the winter by 2025. Our projection periods there went from 2020 to 2030. And also occurred in Southern California by 2030. So, winter loads were always more affected than summer loads. If you're thinking about electrifying space heating, then that makes sense.

And, you know, we have the summer loads growing at the usual times for the entire forecast period through 2030. We didn't forecast past that. So, those would be in the late afternoon and would come with the usual problems of, you know, renewables ramping down and so on, and it would exacerbate those.

Now, if we're thinking about winter loads, you

know we've never thought about a winter peaking system in the State of California, right. That would be a new things for electricity planners to start considering if we electrify at those levels. And even more so because those load peak dates and times would change from those evening hours to early morning hours, like 6:00 in the morning.

All right, so we can't actually use the AB 32 scenarios specifically to start with for AAFS because they are what-if, speculative scenarios. And we're currently working and have been working with our contractor, Guidehouse, on incorporating more program-oriented inputs into our improved Energy Efficiency and Fuel Substitution Analysis Tools that we plan on using to collect -- not collect, but to analyze the data that's then been collected towards the 2021 IEPR.

The next slide, please. So, for 2021 we wish to develop additional achievable fuel substitution as an hourly load modifier to the baseline demand forecast. We are now conceptualizing this AAFS as being separate from AAEE. But we do want to use it in a manner similar to the one that was developed for AAEE. So, basically using the AAEE template for AAFS work.

So, as a reminder AAEE was developed starting in 2009. It wasn't called that until a little bit later.

And then, the Joint Agencies developed the single forecast set language and formalized it in 2014.

The next slide, please. So, what we've done to support the development of AAFS thus far is we gave the Joint Agencies, the JASC, a presentation at our quarterly meeting on June 4th of this year. And we had a very robust discussion of what these different scenarios could be, what they could be used for, et cetera.

Then we took this to our Demand Analysis Working Group, which is our broader technical stakeholder working group, and we had many utilities participating in that on June 23rd.

We've also had many discussions with utilities while we were trying to collect electrification or fuel substitution data from them on programs that they're developing, or proposing to develop, and so on.

So, as in the 2019 AAEE forecast and before, our objective is to continue to focus on firm projections for this forecast, since the core scenarios will be used for planning and procurement purposes.

As in previous iterations, we would like to develop variations around the most probable futures for AAFS, as we did for AAEE, to show other possible outcomes given either less or more effort put in to

realize the potential of existing or proposed EE and fuel substitution programs.

The next slide, please. So, this is where we listed out the elements or, you know, the fuel substitution elements that we have been considering for inclusion in our AAFS scenarios. These were shared at the JASC, as well as at the DAWG. We looked at, you know, different -- they all have different levels of uncertainty associated with them.

So, if one were to start building scenarios from being, you know, ones that are focused on firm programs all the way out to ones that are still a sparkle in someone's eye, then we could start with the red boxes and say, well, you know, these are things that are happening.

We have the 2021 IOU Potential and Goals Study measures. We have the IOU data that's already in CEDARS on recent fuel substitution activities. We have been collecting POU data on their recent fuel substitution activities.

And then, of course, there are local ordinances. So, these are ordinances that local jurisdictions have developed and that are requirements in, you know, those cities or counties that have chosen to adopt them. And since 2019 there have been many that are encouraging

electrification of some or all end uses. And then, there are also local natural gas bans. So, all of these things would be looked at as fuel substitution where that construction in those jurisdictions would then no longer be mixed fuel, and gas would be displaced, and local electric load would be added.

So then, more recently, in yellow we've developed -- or, now we specifically, but the Energy Commission, and the Efficiency Division, the Building Standards Office has been very hard at work at developing the 2022 Building Standards. And those are including electric baselines for prescriptive compliance for new construction.

So, again they're strongly encouraging electrification and the uncertainty might lie in, you know, what builders actually end up doing. So, the impacts will depend on how many buildings will be built towards a prescriptive compliance that have an electric component to them, or how many will be built using the performance compliance metric.

Then, we also know here that the Build and Tech programs, they are being rolled out, they are funded, right, but there hasn't been any implementation. So, it's unclear exactly what the impact is. There's some

uncertainty.

So then, of course, everything on this list here, including some programs that we've been collected data on outside of the energy efficiency portfolios, but that are focusing on fuel substitution, you know, if it made the list then there's some information that we can work with here.

And then beyond that we're, on the right-hand side, trying to demonstrate our Blue Sky scenarios. Right, we can take all these programs, we can ramp up their, you know, compliance rates, their funding rates. We can be very optimistic about the assumptions that can go in there. And then we could start adding, for even more Blue Sky scenarios, like the speculative programs that we're hearing about from utilities and others, as well as look at how those are going to possibly meet AB 3232 goals, or longer term or, you know, a benchmark on the way to the longer term mid-century climate goals.

So, the next few slides just sort of go through this in a little bit more detail, so I think we just go next slide. And next slide. And we're just building these scenarios up from being most conservative to more optimistic.

Next slide. So, this would be using everything that we have data on.

Next slide. And this would be saying, making the most optimistic assumptions about those programs that do exist and will exist.

Next slide. And this is where we're starting to go into add more speculative programs that might actually meet those minimum AB 3232 goals.

The next slide. And then, all the way up to the most ambitious 6th scenario, which would then perhaps meet those economy wide mid-century GHG reduction goals.

And my final slide, please. Ah, almost final slide. Okay, so this brings about two points. We do have to consider how these two load modifiers, AAFS and AAEE will work together because we do have a finite amount of total gas displacement potential, as well as program funding sources.

And then, of course, as I mentioned we're going to further consider who will be using this AAFS and for what purpose, and that might require our reassessments of what goes into that single forecast set language.

And the next slide. So this, indeed, is my last slide, just giving a timeline of where we're at right now, the August 5th workshop. We've had a lot of staff-to-staff discussions with all of our stakeholders.

And then, we're going to narrow down some of these preliminary scenarios designs in a discussion with

the core agencies here involved in JASC, before we present our preliminary scenario designs for both AAEE and AAFS at a late August DAWG meeting. Then, we can start running numbers and making sure that those scenarios make sense before we present them at the end of September in another DAWG meeting. And then after that, we will be able to make any final adjustments before we share those with our core forecasting unit, so that Cary and Nick can incorporate those in the management forecast that will be going to the December 2nd IEPR.

Thank you very much.

COMMISSIONER MCALLISTER: Thanks. Thanks Ingrid, that was super helpful. Just a couple comments and then a question. So, thank you for that, I always -- you know, these are really critical modifiers to the demand. And so, you know, AAEE we've been doing that for a while now and I think, you know, it morphs, I think we're pretty much in tune with, you know, sort of ears to the ground on what's happening out there in the marketplace to be able to modify that each IEPR cycle.

And I do have a question about that, but just hang with me here. And then, the AAFS, I think it's hard to kind of overstate how foundational that is for our now longer-term demand assessments because that's

going to -- the drivers, the assumptions, you know, behind that really are going to move the needle in a big way, you know, and compound year to year. And that's a powerful thing. And I think we're going to see how policy shapes that, how the marketplace responds. And really need to -- and we all know that that's -- there's a fair amount of -- there's a fair range of possibilities there to how the marketplace responds and sort of how quickly we can push. But, obviously, decarbonization -- for decarbonization is a critical component. We're just not going to get to our long-term goals without a fair amount of electrification, at a minimum.

So, one of your final slides there, you know, you talked about sort of who is going to be using the AAFS. And I think I wanted to highlight, you know, we always talk about the PUC and the ISO, but I think increasingly our outputs are going to feed the ARB scoping plan discussion, and you know what's --- how our buildings and our mix of fuels really impacts the emissions trajectories that the ARB is responsible for developing as part of the scoping plan.

And so, I would just encourage, you know, building of those bridges at all the staff levels and then, you know, we'll certainly be coordinating at the

principal level to make sure that we're in alignment there because those are real impacts on our various tools, so that integration is really key.

So, just a few things I wanted to point out. So, you know, it is true that the electrification will impact the -- you know, if we're talking about electrification of heating loads, you know HVAC particularly, it will change the winter peak. But I will just point out that the winter peak is actually a lot lower than the summer peak, and so that will tend to be a relatively benign change that will improve overall capacity factors on the system. And we should have, you know all the indications are that we should have enough resources to get through the winter with that sort of additional electric load. It's not going to drive a lot of -- it might vary a little bit throughout, you know, different parts of the state, but it's not going to drive a lot of incremental infrastructure investment. Because still in most of the state it's going to be driven by the summer peak.

And then the summer peak itself is shifting as well. So that, you know, again it's spreading out. Maybe the net peak is going to be moving, you know, one way or the other and it's not -- these additional air conditioning loads, and particularly in your house,

Commissioner Monahan, and elsewhere, maybe have new incremental AC.

You know, kind of one thing that we have our fingers on the pulse of is where that load comes in sort of temporally and whether it does or does not impact the overall peak, and the net peak. And I think, you know, it's likely, and particularly as we accommodate load flexibility in that electrification likely that these new end uses become tools for enhancing reliability.

So, I think, you know, we all need to sort of focus on that, and the same would be true for the transportation electrification, right. So, really, really sort of all hands on deck in a coordinated way, making sure that all the functionalities are there to support reliability.

So, with all that said, I think -- well, one last point, actually. One new source of data which I think is -- I'm really excited about and I know Commissioner Gunda likely is, too, is we're getting -- you mentioned CEDARs, the PUC, and some of the long-term data sort of consumption pattern data. We're going to be doing -- really upping our game in the near term now, getting in AMI data and, you know, from much of the state, and that's going to open a lot of windows in terms of understanding the trends, understanding the

consumption intensities, unpacking that, and all sorts of, you know, slicing and dicing that in all sorts of ways. Understanding the sort of energy usage intensity sort of trends in our building sector, for example.

So, I'm really excited about that. And that insight that we'll get from the sort of aggregating customer level data in different ways, and looking at it temporally where we have AMI data, interval data, that's going to really help, I think, to flesh out and narrow the bands of uncertainty around the AAEE and AAFS.

So, I'm really excited about that and I know our data team is sort of ready, ready with the catcher's mitt to kind of get that data and start to use it.

So, one question. Which workbook, you mentioned that AAEE is morphing and some of the workbooks are going away, and some of them are coming in, well maybe you could let us know specifically what those components -- how those components are changing?

MS. NEUMANN: Yeah, so I mean in some way it's as straight forward as just saying that, you know, there won't be a fuel substitution workbook because we're treating fuel substitution separately in a more sophisticated manner.

Then, we will -- one thing that's being removed is the Benchmarking Program. Because apparently it's

hard to tell whether those efforts are directly transferrable to actual energy efficiency savings. And that's sometimes an argument that -- so, this was coming directly from the program administrator, where they're saying they don't feel comfortable reporting this as an energy efficiency savings due to that program.

So, sometimes I heard that argument about, you know, oh, maybe AMI data is not going to be that panacea of you're going to all of the sudden know exactly what's going on with efficiency if you know, you know, where an incentive has been applied because sometimes people change their behavior then, right.

So, it's just like if you add solar, then you say, okay, maybe I can turn my AC down a little because, you know, I bought solar so it's okay, right.

Right. So, it's like I think it will give us, you know, more information most certainly. And I'm excited. I was like big smile, right. But it's going to be tricky teasing it out. You know, so it's those kinds of things where we've just learned more about that from the program administrator.

It seems like our AQ -- our Air Quality Management District workbooks, we haven't finalized exactly what we're going to do with those. But that data wasn't very disaggregated. And then, they

basically were saying we're not sure that this is necessarily building energy efficiency data.

But meanwhile, we've actually learned that there are efforts underway by some Air Quality Management Districts to incorporate like a building electrification kind of piece. So, we would want to capture that in the AAFS because they're working on point of sales restrictions.

I mean their focus is on reducing NOx emissions. But speaking to them, effectively that means electrification. So, they say that you could only sell specific appliances using an electric source, no longer the natural gas version, you know, in those jurisdictions.

COMMISSIONER MCALLISTER: Sure. Okay, well thanks a lot. So, yeah, those are -- I think those are relatively long-term trends that we need to pay attention to and, in fact, work with ARB and the AQMDs on that last one to see where they might be going with their regulations that are based on air quality, but that have a really, a potentially a very large impact on end use energy consumption. So, that's something we are and will increasingly be working together with South Coast and other AQMDs on that.

Full disclosure, on your first point about the

sort of take back effect, you know, when you make a measure do you then sort of become more proliferate with your energy, with your use of that measure. Full disclosure, I did write my PhD about the solar take back effect. And so, I can say with some authority that is there is a take back effect, it's actually quite small. And so, you know, people do not massively increase their consumption. They might a little bit, you know, 10 percent, 5 percent kind of thing, and it will vary a little bit.

But the same is true for, say, transportation. You get an EV and you don't necessarily drive more vehicle miles. You get a hybrid and you don't necessarily drive more vehicle miles. There's a certain, you know, a certain take back, a little fungibility there, but it's not -- it's nowhere near the overall impact of the measure itself. And so, whether it's solar or energy efficiency measures.

So, I think it actually is very much worthwhile to keep developing those algorithms to utilize the AMI data to look at trends. And obviously, as you suggest, the attribution may be difficult or maybe, you know, have some uncertainty around it. But I think the trending itself is really important for us to look at and begin to correlate, you know, fuel substitution

measures with any impact on overall consumption. And certainly, the hourly, you know, the load shape impacts.

So, anyway, just I think -- you can tell I'm super excited about being able to delve into some of these tools. We need to automate as much of it as we can. And I think we're making a lot of progress on conceiving that. And just so the world knows I think, you know, the ultimate vision is to have smart people helping us develop, in sort of controlled circumstances, and obviously protecting the data fully to contribute to the library of automation algorithms for different purposes and different analytical goals. And, you know, have a lot of this stuff and, you know, just have a lot of real creativity go into this so that we can invite creativity into our great, innovative, digital state to help us, you know, understand a lot of these trends.

And so, that's the progression that we're moving towards and it's actually happening, which is very exciting. So, great.

All right, so we want to enable you with tools. You know, we want to help you help the state. So, great.

So, anyway, I've gone on too long. We're going to pass the time to Commissioner Gunda, off to you.

COMMISSIONER GUNDA: Yeah, and thank you,

Commissioner. In the interest of time I'm just going to make it a comment and just leave it at a high level.

I think it's just for the public here, a lot of these presentations, when they're all done you don't really know -- I mean, it can be like there's hundreds of conversations that go behind the scenes, and this is really an opportunity, the dialogue between Commissioner McAllister and Ingrid really like showcases the kind of conversations that are happening. And I think it's vital to create that space to happen in the public, so the public understand all the different things we're thinking about.

So, one specific thing as it perhaps to reliability, and I think Commissioner McAllister really teed this up, I just want to make sure that, you know, from the vantage of reliability the forecast, and Ingrid, the work that you're doing in terms of the fuel substitution will be instrumental, both in the short term and the long term in how the electric system, as well as the natural gas system will play out. I should say, the fossil gas system will play out.

And I think it's important for us to, hence, to think about the bookends of the way you laid it out, you know, what's firm to happen, what is kind of aspirational or targeted to happen here, and then the

policy driven. It just provides as a context of the implications of the gas use, or electric use, and thereby allows us to think about these long lead time issues. I mean the electric system, when you talk about the distribution upgrade, you're talking about seven years. We're talking about transmission upgrade, ten years. You know, you're talking about the natural gas, you know, system upgrade in multiple years. We've seen this over the last several years.

So, I think this is extremely helpful from a policymaking stand point to have this visibility.

And I want to congratulate your team for thinking this through and engaging the public in a very kind of robust way. So, thanks and pass it back to Commissioner McAllister.

COMMISSIONER MCALLISTER: Great. Thank you, Commissioner Gunda.

Commissioner Monahan, did you have any questions to raise or an observation?

COMMISSIONER MONAHAN: I don't. Just thanks, Ingrid, that was very helpful.

COMMISSIONER MCALLISTER: Yes. It's so great to hear all the conversations that happen among staff and with stakeholders. I mean we have a lot of expertise in the state about impacts evaluation, and how do you pick

data. And, you know, there's a rich academic literature to all of this stuff, and you have access to all of it, and actually the people who generate a lot of it. So, it's a really fantastic place to be on this time.

Thank you very much Ingrid and team.

MS. NEUMANN: Thank you, Commissioners.

COMMISSIONER MCALLISTER: So, shall we move on to public comment?

MS. RAITT: Yes.

COMMISSIONER MCALLISTER: We have Dorothy to manage that?

MS. RAITT: Yes. And we were going to do a --

COMMISSIONER MCALLISTER: A Zoom Q&A first.

MS. RAITT: Zoom Q&A, but we addressed the questions online. So, yeah, if we could just go to public comment, that would be great.

COMMISSIONER MCALLISTER: Okay.

MS. MURIMI: Thank you, Heather. Thank you, Commissioner McAllister.

So, just a few quick instructions for folks. We're going to have one person per organization commenting, and comments may be limited to 3 minutes per speaker.

And we'll start with those on Zoom. If you are on Zoom, use the raid hand feature. It looks like a

high five at the bottom of your screen.

If you're on the phone, dial *9 to raise hand. We will unmute on our end.

So, we'll start with Zoom. I see Kyle Navis. Apologies if I've misstated your name. Kyle, you may unmute and begin your comments.

MR. NAVIS: Yes, my name is Kyle Navis. That's spelled K-Y-L-E N-A-V-I-S. And I'm a Senior Analyst for the Public Advocate's Office at the CPUC.

So, first off good afternoon Commissioners and staff, and thank you so much for taking comments. From Cal Advocate's perspective this has been a really encouraging discussion and it's good to see historic weather trends considered at this inputs and assumptions stage.

Cal Advocates would encourage the CEC to consider prioritizing explication for the state's extreme heat risk as one of the top priorities in this process. While the CEC has published extreme stack analysis using 2020 market data, these stack analyses are fairly simplistic with unclear assumptions. And having better products available would improve procurement planning at the CPUC.

Similarly, we'd love to echo the concerns expressed by the Commissioners during Q&A, and reinforce

Mr. Fugate's point on slide 47, which noted that while adding the data for summer 2020 to the historical record does little to influence the 1-in-2 determination, it could include the more extreme 1-in-X peak weather variance.

So, Cal Advocate's also encourages the CEC to identity uncertainty ranges around any climate trends that could be applied to the forecast. This might run parallel, for example, to Commissioner Monahan's suggestion to weight recent years more heavily, or else to include extreme weather scenarios in the proposed long-term energy demand scenario should that range of extreme weather exceed the 1-in-X weather variance.

So, this is particularly important for ensuring that we set an adequate planning reserve margin.

In addition, an hourly forecast for any of the higher forecasts, like the 1-in-5, 1-in-10, and so on, would assist parties by identifying the hours in magnitudes of higher load, driven for example by higher air conditioning demand. And those could be used to impute hourly forecasts for the 1-in-10 and 1-in-20 variance in the event that the IEPR cannot provide hourly forecasts for all of them.

Cal Advocates is particularly interested in the probabilities of extreme weather events which could

affect the entire state simultaneously or extend into neighboring regions, and stress the ability to serve native load.

Finally, Cal Advocates would like to see CEC publish a technical report in the upcoming IEPR market materials that explains any and all changes to the forecasting methodology, and includes comparisons to the prior IEPR methodology just for clarity.

So, to summarize, this has been really encouraging to us. We're going to look forward to participating in the DAWG Working Group. Our main points were just please focus on extreme weather events. It would be great if you could develop hourly 1-in-x variant forecasts. And publish a technical report outlining changes to the methodology.

That's all we have and thank you so much for your time and attention.

MS. MIRIMI: Thank you, Kyle. I'll do another call for hands. Again, if you're on Zoom use the raised hand feature, it looks like a high five. Seeing no other hands, I'll pass the virtual mic back to you, Commissioner McAllister.

COMMISSIONER MCALLISTER: Great. Well, thank you very much Dorothy. And I want to just encourage people to -- as always, to submit your written comments.

You know, there's a lot to chew on here. You know, I think we all understand that this not the most accessible topic in the world for lay people, but it's critically important, as I think all of us have acknowledged in our comments, both in the presentations and from the dias. So, you know, I think it's really worth digging in. And really appreciate the public comment now, and very much value and will read every one of the written comments that come in. So, you know, staff is very much on top of that. And, really, the comments are the lifeblood of this process to help us make sure we're not missing anything, and to keep things always updated.

So, with that, that information's there, August 19.

We will pick this up at two o'clock, at the afternoon session and we'll talk about transportations forecast and production modeling, as well as dig into the retail rate assumptions that are behind the forecasting work.

So, with that I want to just invite my fellow Commissioners to perhaps make some closing remarks for the morning. Otherwise, I think we'll pick it up at 2:00. Great. I'm not seeing any.

COMMISSIONER GUNDA: I'd just like to thank you.

Thanks to everyone.

COMMISSIONER MCALLISTER: Thanks to the whole team. Yeah, really good stuff. I'm looking forward to picking up here in a little bit, in the afternoon. Great.

Heather, I think that is it for now.

MS. RAITT: Super. We'll see you then. We'll see you this afternoon, too.

COMMISSIONER MCALLISTER: Great. Thanks everyone.

(Thereupon, the Workshop was adjourned at 12:33 p.m.)

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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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