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CALIFORNIA ENERGY COMMISSION

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	)	Re: Load Modifier
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IEPR Commissioner Workshop on Load Modifier Results

ONLINE BY PHONE AND VIA ZOOM

WEDNESDAY, NOVEMBER 15, 2023

10:00 A.M.

Reported by:

Elise Hicks

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P R O C E D I N G S

WEDNESDAY, NOVEMBER 15, 2023 10:00 a.m.

MS. RAITT: Good morning. Welcome to today's Commissioner Workshop on Load Modifier Scenario results. I'm Heather Raitt. I'm the Director for the Integrated Energy Policy Report or the IEPR for short. This workshop is being held as part of the CEC's proceeding on the 2023. So today is a remote only workshop and so we're using Zoom. It's being recorded and we'll post a recording of the workshop shortly afterwards. And then a written transcript will follow in about a month or so. And the schedule for today's meeting and all the slide decks are posted and docketed on the Energy Commission's IEPR web page. You can find it there. We'll have a number of staff presentations today. And then following the presentations, we'll have some opportunities for comments or excuse me, questions from attendees. You can use the Zoom Q and A feature if you have a question you want to type in.

MS. RAITT: And then if you see a question there that looks like one that you had, you can also just upvote an existing question, hit that thumbs up icon and it'll upvote it. And then finally, at the end of the day, there's an opportunity for public comment and we welcome comments. We'll be limited to them to three minutes per person, one person per organization, please. And we will not be responding to comments or questions from public comment, but we look forward to hearing them. And then finally, also written comments are welcome and they are due on December 1st. And with that I'll pass it over to Vice Chair Gunda, who is the lead for the forecast. And then Commissioner Monahan has also joined us and she's the lead for the 2023 this year. Thanks.

VICE CHAIR GUNDA: Thank you, Heather. I just want to begin by welcoming everybody that joined the call today to get through the forecasting draft results. Just want to acknowledge the participation of the interagencies in what we call the Joint Agency Steering Committee that really brings together CPUC staff, CEC staff and CARB staff on a regular cadence along with CAISO to really think through the modeling improvements and the assumptions that we put in and such. So just want to give a big shout out to the interagency team that supports this work at CEC. And specifically at CEC, I would just like to recognize the distributor generation team, the self-gen team that does the forecasting on the self-gen side. Just a couple of people there, Alex, Mark Palmere, Bobby Wilson and Sudhakar Konala who really work on those areas. And the fantastic job that Alex is doing in taking leadership and implementing this huge number of changes. On the transportation team, most of you who are regular to that, to our work now. Our core team, Aniss Bahreinian, Maggie Deng, Jesse Gag, Liz Pham, Namita Saxena, Elena Giyenko and Farzana Kabir, just want to recognize their work on the transportation side that we'll also hear.

MS. RAITT: One of the critical changes this year is around the additional achievable energy efficiency and the additional achievable fuel substitution. We have been making incremental progress on really understanding the demand modifiers as it pertains to building electrification and efficiency and really synchronizing with CARB's scoping plan, the state implementation plan and other initiatives and policies that the state has. So I really want to highlight the leadership that we have there in Ingrid Neumann, Nick Janusch, Ethan Cooper, Usman Muhammad, Cynthia Rogers, and Brian Samuelson along with Mike Jaske.

So just a big thank you there to all the people. So this year some of the core elements that we're continuing to navigate is how do we protect the system planning in terms of really understanding the variability around not just the weather, but the demand modifiers and the load modifiers that we're going to discuss today.

I made some huge changes in terms of implementing new modeling in terms of the self-gen forecast, but also continuing to pay attention to the liability and affordability. So I think it's kind of a balance that we need to do as a state to plan for high electrification future with ensuring that we're building the right levels for reliability and affordability. So really looking forward to the conversation today. Again, a big thanks to the IEPR team for their work. Big thanks to all the interagency team and participants, the stakeholders who regularly work with the team, with the CEC team on developing the assumptions and modeling. So big thanks all around and also to Commissioner Monahan for the CS leadership. With that I'll pass it on to Commissioner Monahan.

COMMISSIONER MONAHAN: Well thanks, Vice Chair Gunda. And I just want to say the one person who didn't get acknowledge in that long list was you for your leadership in terms of really helping the Energy Commission improve our forecast and be proactive in evaluating the impact of regulations that have not yet been passed but are still under development. And I would say in some way transportation was the camel's nose under the 10th in the electrification world, and now we're seeing sort of the same phenomenon play out when it comes to buildings and potentially, eventually industrial applications as well for electrification. So I think it has been - I was appointed, I was thinking about this in terms of my trajectory here at the Energy Commission. So I was appointed by the Governor in 2019. That was the first year I would say that the forecast started to show a future of increasing electrification.

COMMISSIONER MONAHAN: And then every year since then, of course, the demand forecast has projected more and more electrification going forward as a key climate strategy. And it's just been really amazing actually to see in my short time here at the Energy Commission, how the work of our forecast has deepened and strengthened.

Transportation is the area that I'm tracking most closely, and it has been just really amazing to see how the team has deepened our understanding of what transportation electrification is going to need for grid planning. So just looking forward to this workshop. Thanks to Heather for her leadership on all things IEPR and really looking forward to the conversation. Thanks also for switching the agenda. I have to say that I have to leave in the afternoon, so the morning is going to be transportation, which I really appreciate the flexibility on the agenda. And I'll pass it right back to Heather.

MS. RAITT: Thank you, Commissioners.

So our first presenter is Quentin Gee. He's the Manager of the Advanced Electrification Analysis Branch. And so he'll be kicking us off. Thank you, Quentin.

MR. GEE: Great. Thanks, Heather. Hi, everybody.

My name's Quentin Gee. I'm the Manager for the Advanced Electrification Analysis Branch and also acting supervisor for the Transportation Energy Forecasting Unit. And maybe before we get started with this, maybe we could go back one slide and we'll stay on this slide for a little bit and I'll provide a little bit of context for the overall load modifier discussion that we're about to have today. And then I'll jump into transportation in a bit.

But to start off today, today's the 15th where we're doing the load modifier results workshop today. We will discuss transportation electrification, building electrification and distributed energy resources. And then we will also, in December, that's when we'll discuss the final workshop forecast. That's where we'll go more thoroughly through the hourly results and then also the statewide or CAISO wide, statewide type results and dive deeper into that.

But for now, we're going to focus on some of the parts of the forecast that really add a lot of new and interesting effects, have a lot of new and interesting effects on the forecast overall. In January 2024 is when we target the forecast adoption. And so we'll be, as Heather mentioned, we'll be accepting comments now and then also accepting comments at that December 6th workshop on the final forecast for integration into the final forecast for adoption.

For those of you who aren't aware and you you're also interested in some of the forecasting work, we do have what's called a Demand Analysis Working Group or what we call DAWG. That is a working group where we go into more technical detail on some of the work and have more nuanced discussions on some of these issues, diving into the details. So if anyone is interested in that, feel free to reach out to me or contact the IEPR team who can put you in touch with us about getting on that Demand Analysis Working Group list.

But overall, the forecast, and we'll discuss this more also in December, but just sort of as a high level on the forecast, this is a foundational document for a foundational set of data that's foundational for procuring and system planning in the State. This is used by the California Public Utilities Commission for Integrated Resource Planning. It's used by the California Independent System Operator for transmission system planning. It's also used by utilities and the CPUC for resource adequacy requirements and utilities use them also for planning and so on and so forth. We do this at a 15 plus year system level forecast for electricity and gas demand. It used to be a 10 year forecast, but now we have extended it out to 15 and we're going an additional year out this time. And we report the annual electricity and gas consumption for a sense of the overall resource needs.

We do what are called 8760 hourly electricity loads where we are assessing the load on the system overall for each hour of each year, primarily focused on that peak hour. We do scenarios for energy efficiency, building electrification, transportation electrification. And we also have what we call 1-in-2, 1-in-5, 1-in-10, and 1-in-20 year net peak electricity and net peak electricity demands. Sort of evaluating primarily what happens on say a hot summer day, like what's the probability, a 1-in-10 year that we are going to peak out a little bit higher than we might expect.

Every two years during odd number years, we do a full refresh of the forecast, which is what we're doing for this year, and then in even number of years we do updates. We don't update all components of the forecast, which gives us opportunities for the team to make some model improvements. So that's the overall kind of take on the forecast for the IEPR.

Next slide. With that, we can jump into the transportation results. I'll present the top line results and also a little bit of information on the light-duty transportation side, and then I'll hand over to the medium- and heavy-duty lead. So next slide.

This is sort of our best practice. We're going to use a lot of acronyms, initialisms, et cetera throughout this. I think that there has been, yeah, these slides are posted online already, so you can go and download them and if you're worried about an acronym or initialism that you see in these next slides, you can go ahead and just jump to that slide or keep that open if you're not familiar with some of this. But it saves us some language or some character space on the rest of the slides where we'll try to focus more on the data. Next slide.

So I'm going to present, yeah, statewide electricity for transportation and also some of the light duty results and a little bit on Off-Road as well, which is a new and emerging sector that we're really going to want to pay more attention to in future years now that we've covered a lot in developing light-duty and medium- and heavy-duty forecast scenarios. Next slide.

So basically transportation is kind of simple. This diagram makes it look simple, that is. It actually is a very complicated set of models that we have a sophisticated set of economic models and other models that really help us understand the transportation energy demand. But sort of roughly speaking, we can say that basically you've got a certain number of vehicles in the population. Those vehicles travel, they drive around the state and those vehicles to do that travel, they need a certain amount of fuel to do it, and their fuel economy tells you how much energy you'll need overall. So vehicles, times the amount of travel, times the fuel economy basically gives you the transportation energy consumption. We tend to break it down into light-duty, medium- and heavy-duty, and we are also thinking more about off-road vehicles as well. But yeah, that's the gist of how it works overall and more detail is available in this year's and previous IEPR's and always open for questions as well during this and our Demand Analysis Working Group meetings. Next slide.

Just to give you a little bit of updates to the light-duty models that we had this year. We do have personal vehicles, which are the dominant form of light-duty vehicle ownership out there, people that just own a vehicle and drive it around for their own personal needs.

MR. GEE: You have commercial vehicles. The personal vehicles and the commercial vehicles. Those are choice models where we have probabilities of new vehicles or used vehicles being purchased by different entities, either people or households or fleet operators, and they choose based off of desired characteristics that are informed by our California Vehicle Survey, which we're actually doing an update to in the next couple of years.

We also have government, rental cars. They're a little bit different than commercial vehicles, which are more like fleet oriented versus rentals where people just do rental stuff with those. So we have government, rental models.

We also have a neighborhood electric vehicles. You can sort of think of golf carts or other small, small vehicles that really don't go on highways or anything like that.

So those are the general models that we have for the light-duty forecast. We have the baseline forecast, which is updated with the latest economic forecast from Moody's. We have Department of Finance household forecast. We revise our fuel price forecast. Vehicle ranges, we update those, update the vehicle prices. We have a new approach to updating the incentives. As one might imagine with the recent Inflation Reduction Act that was passed last year, there have been some changes overall to the incentive structure. We integrated that in last year, but did make some additional updates based on new announcements that were made earlier this year.

We also have the AATE Scenario 3 that's Additional Achievable Transportation Electrification Scenario Three. We didn't do a Scenario 1 and 2 this year, which are defined in different ways. But Scenario 3 really captures the latest and greatest of the light-duty vehicle regulations. That includes Advanced Clean Cars 2 or ACC 2, and also the Clean Miles Standard.

The Clean Miles Standard is a regulation on transportation network companies, such as Uber and Lyft. And requires them to, for the vehicles, the vehicle miles traveled of the vehicles for their services have to be increasingly electric at an accelerated rate compared to simply what we would expect under the Advanced Clean Cars 2 regulation. One little caveat here, I know this is something that can come up and it's a little confusing, but the Class Two B vehicles, this is kind of an interesting little category here that is a little bit strange for analysis, but roughly stated, we count Class Two B - so Class Two B vehicles, these are gross vehicle weight rating of 8,500 to 10,000 pounds. That is the car loaded to its typical recommended maximum capacity. The gross weight of that whole thing is about 8,500 to 10,000 pounds. You can imagine here we've got the little cutouts of what is a Ford E-Transit that has a gross vehicle rate rating of 9,500 and then we have, I think that's a silhouette of a Ford F-250 or something like that.

So not quite the standard pickup, but a little bit of more the heavy-duty ones. Those count in our models, those count as light-duty if their gross vehicle weight rating is less than 10,000 pounds, but greater than 8,500 pounds, that is treated by the California Air Resources Board differently, that is treated as a medium-duty vehicle. So it could be counted under the California Air Resources Board Advanced Clean Fleets rule, but it could also count under the Advanced Clean Cars 2 rule.

It's a little bit tricky. For our modeling purposes, we found it most efficient to just treat them as light-duty and have them superseded by Advanced Clean Cars 2, which is in many ways a stronger regulation in terms of getting more zero emission vehicles on the road. Next slide.

So here are the results overall. In the dashed, you can see the last year's ATE 3 Scenario and in the orange you can see this year's scenario. It's a little bit lower.

Then in the blue you can see the baseline forecast. The baseline forecast does not, as we saw in the previous slide, it does not capture Advanced Clean Cars 2. It's kind of like how we might envision zero emission vehicle adoption to occur without that requirement being operative. So pretty similar, although it does look like there's fewer ZEVs overall.

I should note here, I think I mentioned Advanced Clean Cars - excuse me, AATE 2 and 1. You'll notice that the distance or the gap between the baseline and AATE 3 is pretty small, and if you've seen previous year's forecasts that that gap is a little bit bigger. Because these two were so close, it didn't seem like AATE Scenario 1 or AATE Scenario 2 would've been particularly informative because there's just such a close band in between those two. So looking at AATE 3 in the comparison, as I mentioned before, we do have the difference quite a bit of or reasonable difference between AATE 3 for this year and also AATE 3 from last year, particularly 2035. It looks like there's about a million, a million and a half fewer Zero Emission Vehicles on the road.

Each forecast year has different inputs. Things change in the models, but one thing I should point to is on the next slide, we think is probably one of the leading drivers, not just for our results but also for the forecast as a whole. But on the next slide we can see sort of a leading driver in the ZEV difference. The big issue here is that there's just fewer households. Basically, you can see that dash line showing the household forecast going out through 2035, and then you can see this year's it's actually gone down by quite a bit, 800,000 households. So that's one of the leading drivers of the reduction in vehicles. There's just fewer households out there that demand vehicles and that builds up over time. Next slide.

Sort of zooming out, looking at transportation overall. Here are the electricity demand results for all of transportation. I should clarify here that this is not exactly what goes into the hourly load models. There's a little bit taken out here, but I'll describe that in a second when we break it down. But this is just generally sort of to give the folks here just a broad sense of how much electricity we anticipate to be used for transportation purposes. Pretty close to what we had in the previous year. The leading driver here is that we do have the Clean Miles Standard that has more electric or Zero Emission Vehicle miles traveled. And we also had some additional updates. Maggie will be able to talk about those with the freight forecast, et cetera. But overall pretty close to what we had in the previous year and growing electricity demand quite a bit that we'll need to be planning for, but not a huge change from last year. Next slide.

So here's another way of looking at more or less the same thing that we had before. And here of broken it down a little bit in terms of the different components that make it up. So basically broke down the commercial, government, rental light-duty, put those in the blue and then in the orange you can see the medium- and heavy-duty freight. In the green we have personal light-duty. You can see that that's the major source of demand for electricity.

We also have trail transit, rail and other buses making up a small but noticeable portion. And then, finally, I could draw your attention to this, what we call off road electrification. This is something that's been a part of the forecast, but I will, that is not a part of the load modifiers. So the off-road electrification currently is treated as just sort of a component of the baseline demand that goes into the baseline forecast and is not treated differently compared to say the personal - excuse me, the light-duty vehicles or the medium- and heavy-duty vehicles.

And I think it might be worth us taking a closer look at that. So on the next slide we can take a look at the breakdown of the off-road electrification. This is an area where we're going to need a lot of development in the future on this. We do have an off-road model and have been using it for several years now. We're pretty happy with it, but overall we do need to really expand some of the areas that we're looking at, update some of the work here, and also integrate some new regulations on this front. But we think we've got a pretty good sense of it right now, but just looking to improve this in the long run.

But we have construction, other off-road equipment, agricultural equipment, shore power. That's basically when a ship docks in harbor that they rather than continuing to use their engines to generate electricity for their needs that they plug in at the port and we'll use electricity there rather than running engines and creating pollution from that.

There's also port cargo handling equipment, things like forklifts and sort of pallet lifters or trailer lifters or I can't remember what those things are called at the ports. The container ship, the container lifters, those sorts of equipment. And then also forklifts overall. Electric forklifts are expected to increase as well. There's a lot in use already, but we anticipate even more in the future. We want to get a closer read on these and longer term we are thinking about ways in which we can integrate the forecast results here into other looks or other assessments of different segments of the economy. In particular agriculture and the ports are things that we want to take a closer look at in the future to help inform some of the grid work that's necessary in those areas.

With that, I think we can hand over to the next person. That is Maggie Deng. She is the MDHD forecasting lead. Maggie.

MS. DENG: Hi. Good morning, everyone. So as Quentin mentioned, I'll be presenting on the updates and results for the medium- and heavy-duty component of the IEPR Demand Forecast. Next slide.

So just to set the stage with some definitions, here's an overview of all of the different weight classes and general vehicle categories that we define as MDHD for the forecast. Simply put, MDHD for our forecasting purposes is anything from gross vehicle weight rating three up to eight. As Quentin mentioned in his presentation, many of CARB's policies such as Advanced Clean Trucks and Advanced Clean Fleets include Class 2 B, but for our models, Class 2 B is considered light-duty and therefore handled by our light-duty models. All of the boxes here in light blue are included in our Freight and Truck Choice Model, which I primarily work on and all of the boxes in white are included in our travel choice models, which is led by my colleague Elena Giyenko. For the HD trucks, I wanted to note here we have some classes broken out by application such as delivery trucks and vocational trucks. This is a crucial distinction since the Vehicle Miles Traveled, or VMT, and travel patterns of these MDHD trucks will vary greatly depending on their application. Just as an example, a class eight tractor trailer combination truck that operates only within California will typically have a lower annual VMT than a tractor trailer truck that's registered to travel for interstate.

MS. DENG: Finally, on the rightmost column we also have different types of buses broken out with some falling under what's called the urban under city model and the rest being included in the other bus.

Can you all still hear me clearly? Not sure if there is an audio issue.

MS. RAITT: Yeah, Maggie. This is Heather. We can still hear you but you did get quieter, so I'm not sure if you can just maybe speak up a little bit. That'd be great.

MS. DENG: Sorry, is this better?

MS. RAITT: That's better. Yep. There we go.

MS. DENG: That's better. Okay, great. Thank you so much for pointing that out. Okay, next slide.

Alright, so here's a quick summary of major updates to our MDHD models starting with the baseline forecast in the middle column. I won't read off every bullet point here, but generally speaking for all of our MDHD models, we incorporated the latest economic forecast from Moody's Analytics, updated key inputs such as fuel prices and truck prices and calibrated to historical fuel consumption. For AATE Scenario 3 on the right hand side here, no changes to baseline forecast were made for buses, which again are modeled under our other bus in urban inter city models. However, for the freight and truck choice model shown here in the top right. This year's AATE 3 includes the recently formaly adopted CARB ACF ZEV requirements and, most importantly, for the first time this year, we've incorporated a cutoff of internal combustion engine vehicles beginning in 2036 in order to reflect the manufacturer ZEV sales mandate under ACF. I'll talk a little bit more about that later. Next slide, please.

Here we provided more so as a reference for you all, a summary of policies, programs, incentives, and regulations for MDHD vehicles that we include in our models. For our baseline forecast, I wanted to note that we do model Advanced Clean Trucks as part of our baseline. We include the Inflation Reduction Act, Commercial Clean Vehicle Tax Credit, as well as the HVIP incentives. And on buses, we have Innovative Clean Transit California electric school bus program as well as we are modeling some recent regulations for commercial harbor craft and California's in-use locomotives. Again for AATE 3 we're adding on in addition to what's already included in baseline forecast. The key addition here is Advanced Clean Fleets with the fleet ZEV requirements and then again that a hundred percent ZEV sales requirement beginning in 2036. Next slide.

So now here's our first look at results for this year's IEPR. This line graph is showing total MDHD ZEV stock, so this is a sum of both MDHD trucks and buses for both battery electric and hydrogen fuel types. The baseline forecast is represented here in blue as the lowest line on the graph. This year's AATE 3 in orange at the top and last year's AATE 3 in the green dash line. As you can see this year's AATE 3 ZEV stock generally follows the same growth trend as last year with minor differences here I would attribute to the updated economic forecast being used. In 2040, there are a little over 735,000 MDHD ZEVs for AATE 3 and for baseline there are about 455,000 ZEVs in 2040. Next slide.

Now let's take a closer look at just Zero Emission MDHD trucks for our AATE Scenario 3. On this bar graph, I've broken out the zero-emission freight truck stock. Again, for AATE 3 into the fuel types with electric stock in blue and the orange being hydrogen stock. So starting in 2036 ACF ZEV sales mandate for manufacturers kicks in, meaning that new ICE trucks are no longer available in our truck choice model. In other words, electric and hydrogen compete directly with each other for market shares beginning in 2036. This results in about 10,000 hydrogen trucks in 2036, growing to about 65,000 hydrogen trucks in 2040. That means in 2040 hydrogen is about 6 percent of all freight trucks and about 9 percent within ZEVs. Next slide.

So before I move on to further results, I wanted to highlight some key points regarding hydrogen trucks in this year's AATE 3. As I mentioned, the higher level of hydrogen truck proliferation for this year's AATE 3 is a direct result of our implementation of ACF’s a hundred percent MDHD ZEV sales requirement. When battery electric vehicles and fuel cell electric vehicles become the only options in the truck choice model from 2036 onwards, that allows FCEVs to enter the population, particularly for our heavy duty long haul truck classes. Additionally, this year's fuel price forecast was updated to reflect recent spikes in hydrogen price for the earlier years of the forecast.

It's also important to note that currently based on staff and previous consultant market research, our freight model has FCEVs as a fuel type for only class six and long haul class eight trucks. We're keeping an eye on FCEV market developments and welcome feedback for future modeling.

Lastly, the model currently assumes that hydrogen fuel infrastructure will be available, when FCEVs are commercially available, but, of course, this is something that we're going to keep our eye on for future modeling as well. Next slide.

So returning to our results here, I provided another bar graph looking at AATE trucks only, but this time with the breakdown of ICE trucks in blue versus the zero-emission trucks in orange. In 2030, there are about 168,000 ZEVs and they grow pretty rapidly in the 2030s, arriving to about 708,000 zero-emission trucks in 2040. Or, in other words, about a 70 percent zero-emission share of total truck stock in 2040. And, as was the case last year, our ZEV population here should be pretty close to CARB's projections of ZEVs under both ACT and ACF. Next slide.

Alright, one final bar graph here. We're taking a look at AATE 3 stock again, but this time it's total MDHD, meaning it's trucks and buses together here. As you can see with MDHD trucks in blue and buses in orange, the majority of our forecast of the state's MDHD stock are trucks, with about 643,000 electric MDHD trucks and about 23,000 electric buses in 2040. Next, we'll take a look at the fuel consumption resulting from these MDHD electric vehicles. Next slide.

So I'll conclude here with a line graph showing the electricity demand or fuel consumption resulting from the electric MDHD stock that we just saw. The trends here look very similar to the line graph that I had at the start of my presentation of total MDHD ZEVs shown in blue. The lower line here are the gigawatt hours resulting from the baseline forecast with the little over 10,000 gigawatt hours in 2040. Shown here in orange again, AATE 3 electricity demand follows closely with last year's AATE 3 results. The growth of electricity demand in AATE 3 results accelerates in the later years of the forecast, arriving at about 19,000 gigawatt hours in 2040 for all MDHD and AATE 3. That concludes my overview of updates and results for MDHD in this year's IEPR. I look forward to any questions and comments, but I'll pass it off to my colleagues Liz Pham for load shapes and regional energy allocation.

MS. PHAM: Hello, everyone. My name's Liz Pham. I'll be going over the regional energy allocation and load share. Next slide, please.

MS. PHAM: So what Quentin and Maggie just presented are the statewide energy consumption. What I do for the regional energy allocation is I further break down the statewide to forecast zones. We have 20 forecast zones, but we only focus on 15, which we then aggregate up to the five planning area.

MS. PHAM: as or what I like to call utilities. So PG&E is forecast zone one through six, SCE is seven through 11, SDG&E is 12, SMUD is 13, and LADWP is 16 and 17. And then the other forecast zones that are shaded in black, those are the other utilities. I also linked an arcGIS map of the forecast zone if people want to explore.

MS. PHAM: So essentially for the regional energy allocation, I'm answering the question where are people consuming energy at the forecast zone level and how much? Next slide, please.

MS. PHAM: In terms of energy allocation, Maggie does the medium- and heavy-duty and I do the light-duty vehicles. So for this I'll just be going over the light duty vehicle. I actually wanted to go over the inputs first before the methodology. Here, I wanted to just point out the differences in the inputs compared to last year. Our model uses vehicle miles traveled from EMFAC 2021 and this was updated to the newest version. For DMV registration, last year we used 2021 vehicle population. This year we're using 2022 vehicle population. And, in terms of economic demographics, we used the updated household and income forecast that was produced by the CEC. For the methodology, I quickly want to go over how the regional model works. The gist of it is that it uses DMV registration data to determine where energy is consumed at the forecast zone level. So we do assume that where someone registered their vehicle is also where the vehicle was charged.

MS. PHAM: So this would be mostly home and in-city charging and this is something important to note because - next slide, please - for improvements because we use DMV registration data to determine where energy is consumed, this caused the allocation to be heavily focused on city. So last year when we presented the regional allocation, stakeholders commented that CEC should consider charging along highways or enroute charging. So that's exactly what we did this year. We considered allocating based enroute charging. According to the National Renewable Energy Laboratory EV modeling work known, as EV road trips, about 10 to 12 percent of the VMT constitutes what they define as a road trip likely to need DCFC charging. Therefore, we took 12.5 percent of the statewide energy consumption and allocated using highway traffic data and population density. We will continue to monitor road trip modeling efforts to improve this allocation process, but essentially how this works is we look at major highways in California and where there are more highway traffic but less population density, those areas get more of the 12.5 percent.

MS. PHAM: Whereas for high traffic areas, with high population density, so highways going through cities, those areas get less up to 12.5 percent. Again, our regional allocation was heavily skewed towards cities and city charging. So now by doing this, it allowed us to shift load from cities to highways in more rural areas that would be used for enroute charging. For assumptions, we are assuming that 12.5 percent of the statewide will be due to enroute charging and this percentage will stay the same throughout the forecast year. It's possible that this percentage could increase in the future due to various reasons like autonomous vehicles, but for now we don't have much data so we just kept it simple and kept it constant.

MS. PHAM: Another assumption is for DMV, we do assume that people are charging or using their vehicles where they're are registered. So there could be instances where people are registered in one city but they're using their vehicles in a different city. Next slide, please.

MS. PHAM: Okay, so for results. Here we are looking at energy consumption for light-duty plugin electric vehicles for each of the utilities. This slide, I wanted to compare what it would look like with and without enroute charging. In the orange column to the right, this is where the energy consumption would have been in 2040 without enroute charging. So this is mainly city charging in the blue to the left of that is the result with enroute recharging. So this essentially decreased the energy consumption for LADWP, SCE and SDG&E and reallocated to more rural forecast zones which affected PG&E, SMUD and the other smaller utilities. So with this improvement for LADWP, energy consumption decreased about 300 gigawatt hours. PG&E increased about 800 gigawatt hours. SCE decreased about 900. SDG&E decreased about 300. SMUD increased about eight and the other utilities increased about 700 gigawatt hours. Next slide, please.

MS. PHAM: Now we are moving on to the EV load model, which produces our load profiles. So for the regional allocation we wanted to know where people are consuming energy. Now for the load profiles, we want to know when people are consuming energy and how much. For anyone who's not familiar with 8760, this is essentially how many hours there are in a year. So 24 hours in a day, times 365 days equals 8760 hours in a year. Next slide.

MS. PHAM: For the EV load model, just a reminder of how it works. It essentially takes our base load shapes that we got from ChargePoint and Lawrence Berkeley National Lab and this shifts the load according to TOU rates, elasticity factor, so this is how responsive customers are to TOU rates and TOU participation, so this is the percentage of customers that are on TOU rates.

MS. PHAM: For the inputs, again, I just want to go over what is different compared to last year.

MS. PHAM: For TOU rates, every year I update the TOU rates for each of the utilities. I generally use EV specific TOU rates, but if utilities does not have EV specific TOU rates, then I would use the regular TOU rates. And then usually there's an EV credit or EV discount that can be applied to certain hours. So that's generally true for SMUD and LADWP and those are updated as of September 2023.

MS. PHAM: For load shape, the LDV, the light-duty vehicle uses 2017 ChargePoint data and the medium- and heavy-duty uses load shape that we got from Lawrence

Berkeley National Lab and those stayed the same as last year. Elasticity factor and TOU participation that these both stayed the same as last year as well. Next slide, please.

MS. PHAM: In terms of improvements this year we added seasonality. To do that, we used quarterly averages of monthly gasoline and diesel sales tax from the California Department of Tax and Fees Administration.

MS. PHAM: Here we have index charts of the gasoline and diesel sales that we are assuming is indicative of energy consumption. On the left side is an index chart for gasoline sales tax that we're assuming will inform light-duty energy consumption and on the right is a index chart of the diesel sales tax that we're assuming will inform medium- and heavy-duty energy consumption. So both have similar distributions. You'll see lower energy consumption in the winter month. So month one, two and three, which is January, February, March. And then more energy consumption in the summer months, so months seven, eight, and nine, which is July, August and September. So essentially adding seasonality will shift more load to the summer months from the winter months. Next slide, please.

MS. PHAM: Assumptions again, we are assuming gasoline sales tax informs light-duty seasonal electricity demand and diesel sales informed medium- and heavy-duty.

Other assumptions to be aware of our load shapes, elasticity factor, TOU participation. They're all the same in all forecast zones. So we recognize that there could be regional differences for these inputs. We just don't have enough data to better inform them.

MS. PHAM: We are hoping to improve these inputs using AMI data or Advanced Metering Infrastructure data, but that is still to be determined if it's actually possible.

MS. PHAM: Another assumption is that TOU rates are assumed to stay the same throughout the forecast. So we don't actually know what the TOU rates will be in 2030. Next slide, please.

MS. PHAM: Okay, so for results I wanted to compare what it would look like with seasonality and without seasonality. Here we're looking at a load profile from 2035, a weekday in September for the CAISO system for the light-duty vehicles. So the CAISO system is essentially PG&E, SCE and SDG&E added together. In the blue is what the profile would look like without seasonality, and the orange line is with seasonality. Adding seasonality resulted in about a 7 percent overall increase for September in 2035. Next slide, please.

MS. PHAM: And for this slide we are comparing the load profile for medium-heavy duty. Again, we're looking at 2035 a weekday in September for the CAISO system. Blue line is without seasonality, orange line is with seasonality. For medium and heavy-duty vehicles, adding seasonality resulted in about a 9 percent increase in the overall load in September. Next slide, please.

MS. PHAM: Here is the overall load profile for both light-duty and medium and heavy duty for the CAISO system. Again, we're looking at results for 2035 a weekday in September. As you can see, there's a lot of nighttime charging peaking around midnight through 1:00 a.m. and the load dipped around early morning around 5:00 to 6:00 a.m. and then peaks again around 7:00 to 11:00 a.m. and then load decreases during peak hours from 4:00 to 9:00 p.m. when TOU rates are more expensive.

MS. PHAM: In general, the overall shape of the load did not change much from last year. Adding seasonality enroute charging mainly affected the magnitude of the profile. Next slide, please.

MS. PHAM: So this concludes our presentation. Thank you very much. Heather, I'll hand it back to you.

MS. RAITT: Thank you, Liz, and Quentin and Maggie.

So now is an opportunity if Commissioner Gunda or Commissioner Patty Monahan would like to have any questions of our presenters.

COMMISSIONER MONAHAN: Well first of all, thanks Maggie, Liz, Quentin, that was really great. And, like I said, it's just been very - to be part of this or at least to see it happening in front of me, it's just really amazing to see how much deeper, more sophisticated the analysis has become with time.

COMMISSIONER MONAHAN: And I'm wondering, Quentin, I'm going to put you on the spot just to talk about this intersection with our AB 2127 report, which highlights the charger needs in 2030 and 2035, and has an intersection - growing intersection with the IEPR. I wonder if you could just talk about it so that others can understand how these analytical products dovetail and don't.

MR. GEE: Yeah, great. Thanks, Patty. Really happy to talk about that.

For folks that aren't familiar with the way that CEC is - sort of broken down with the different work products, the IEPR forecast is done by the Energy Assessments Division that is a different division than the Fuels and Transportation Division, which is tasked with the Assembly Bill 2127 EV Charging Report. And, as two different divisions, two different approaches. We have done a pretty good job, I think, over the years of being in alignment in discussion with each other in consultation with each other. I think that for our work on system planning or that informs system planning, we've been really sensitive to things like TOU rates and behavior around that. I think Fuels and Transportation Division has been, and the 2127 report has been really interested in learning more about how to assess funding for priorities, charging priorities, those sorts of things.

MR. GEE: I think - so one thing I should say, where we do align, I think generally speaking we align, if you look at our load shapes, they're pretty consistent but they're not perfectly aligned and we're not using them directly. I should point out for the medium and heavy-duty loads - load shapes, what we do is we took an older version of the 2127 Reports, HEVI-Load model shapes, and we use those in the load model that we have that kind of pushes load down a little bit during the peak hours of say 5:00 to 8:00 p.m. or so. That's when we expect peak hours to usually be when we're looking at system peak or peak within a given utility area. And so I wouldn't say that there's a huge, once we push down the rate, once we push down the demand a little bit, it's not like it's cut in half or something like that.

I don't even think it is reduced more than 30 percent at that point in time for medium and heavy-duty loads. There was an update that I think the latest 2127 report did incorporate, which was new load shapes that were more county, geographically sensitive and load shapes that had a slightly different pattern than what we would've expected or than what we had previously.

We got those load shapes a little bit late in the cycle and we weren't able to integrate them and fully sort of vet how we were going to approach it. But we're looking forward to continually working together with the HEVI-Load team to really integrate those load shapes. I think long-term, our goal throughout this next year is really to what the HEVI-Load shapes are will be what our medium and heavy-duty load shapes are. Like the HEVI-Load model that FTD and AB 20, that will be our medium and heavy duty load model results as well.

We still need a lot of coordination there. We need to make sure that we're thinking through Time Of Use rates in the same way to where we're in good alignment there, but we're hopeful that we'll be able to make a lot of progress in aligning it and maybe making them identical.

On the light-duty side it's a little bit different. There are differences. I think the 2127 report I think does explore a lot in terms of potential differences based on maybe like scenario results. What do we expect if there's a lot of direct current fast charging going on? I think there's a gas station model type scenario that is discussed and we're I think trying to be a little bit more conservative in our approach and not wanting to pull too much or to use a scenario that is using that much kind of daytime peaking. If you look at the load - I mean the load shapes that Liz just presented, there is a lot of load happening during the day for EV charging and it does dip a little bit, but we want to be careful not to make it dip too much or not to use assumptions that will say that it is going to dip too much.

I would say in the long term our hope is to use advanced metering infrastructure data to know well how are people charging today? What is their actual behavior? And that could be useful I think to inform the AB 2127 work and our own work because right now we are using sort of pre-time of use rate, sort of big picture charging data and sort of modifying that on the basis of Time Of Use rates based on economic studies that have been out there. But actual data of how people like every meter or lots of meters in the state would be much more helpful to see how are people actually behaving. Because there's a lot of dynamics that can occur around that. But I think maybe I'm saying it more than necessary at this point.

COMMISSIONER MONAHAN: That was great, Quentin. I do think the more we can get real data, real world data and the more we can integrate, as you know, what's happening in the fuels and transportation division, what's - what's happening in EAD and have just build off each other because this is a period of learning. We don't have all the answers and we're just trying to do the best analysis possible with the information that we have. So it's always going to get better, it's always going to be more refined.

COMMISSIONER MONAHAN: And I would say just to comment and maybe I'm not sure Liz or Maggie actually maybe want to comment on this, but in terms of projecting fuel cells and hydrogen demand going forward. As we move to an all ZEV future for medium and heavy duty hydrogen prices really figure very prominently, right, in the choice of what vehicle is going to emerge from our vehicle choice modeling. I wonder if you can just talk a little bit about that aspect of our modeling.

MS. DENG: Sure, yeah, I'll chime in here. So for our freight and truck choice model, it is true that the final field types in our stock results is very sensitive to fuel price as an input. I think that on the light-duty side it's a little bit less sensitive to fuel price. They have other inputs informing the market shares there. But for freight and truck choice, definitely. I think that's why in previous IEPR results hydrogen trucks were quite low and that's due to high FSSAT truck prices and also higher fuel prices. And also that's why I was highlighting in my presentation that hydrogen only really begins to proliferate once that ICE cutoff occurs. In this case in earlier forecast years prior to that 2036 ACSF mandate, when hydrogen is competing against all the other fuel types, the cost of ownership in terms of the truck price delivered truck price and the fuel price make it a little less competitive in our truck choice model.

And so I think that speaks to how hydrogen fuel price, especially, will I think be a key factor in whether FZEVs, how much FZEVs will be part of the ZEV transition. And I do also I guess want to highlight that I think our model supports what I think a lot of research is saying, which is that FZEV is more - or hydrogen as a fuel type is more suitable for long haul trucking where they might have constraints with charging time, fueling time, et cetera. And I think that our model supports that because even within the FZEVs that do proliferate, they're primarily in those class eight long haul applications

COMMISSIONER MONAHAN: And there is an intersection here with the hydrogen hub that California was just designated a hub federally. And the goal of that is to produce clean hydrogen at scale and to cut prices. So if actually we're successful, that will have an impact in terms of our modeling of hydrogen fuel prices and the uptake of fuel cell vehicles.

MS. DENG: Yes, absolutely.

MR. GEE: Thank you. Thanks Commissioner Monahan. Also, to add on to what Maggie said, yeah, I think the hydrogen hub is a critical component that we want to take a close look at and see how things evolve.

And I think what also is great about the hydrogen hub is it's not just in California, it's all over. I think as Maggie kind of alluded to that our fuel models at this point really just do kind of assume that the fuel is easy to access. You're 30 miles away at any time from a station on the highway, it's just a quick mile, a quick drive or in town it's just down the corner.

That assumption doesn't necessarily hold at this time for things like hydrogen. It also kind of doesn't hold for DCFC like for long haul trucking certainly doesn't. So we want to pay close attention to those factors as they evolve.

But I think the hydrogen hub, having different ones scattered throughout I think is going to be something really critical for us to think about and make sure that we have good data inputs going into there. And our hydrogen forecast, we do want to update the hydrogen forecast. We did a slight update this year compared to last year's results in light of some of the increases in price that we've seen. But longer term that the prices tend to come down and stabilize in the forecast and we're hoping that they can come down further or they certainly will not stay as high as they are now because that's going to be critical to seeing the adoption that the choice models are currently saying.

On light-duty, the hydrogen, the vehicles don't seem to be really taking up a lot of the vehicle adoption there. They represent less than 1 percent of all zero-emission vehicle sales. So the continuing, they're not going down to half a percent or a third of a percent or something like that, but still not able to see any sustained growth in penetration at that point.

COMMISSIONER MONAHAN: Vice chair, I don't want to take up all the airspace. Did you have a question?

COMMISSIONER GUNDA: I do have a couple questions, if you're good with it. But I also want to make sure you have time to discuss all the questions you have.

COMMISSIONER MONAHAN: I have one more, but I want you to ask questions and then we'll see if there's time.

COMMISSIONER GUNDA: Okay, awesome. So I think I just want to begin by just extending my gratitude to you, Quentin, Maggie, and Liz. I really, as Commissioner Monahan said it, the evolution of the forecast and the more rigor and not just trigger the clarity and accessibility of the forecast has improved so much over the last few years. I'm just really grateful for your continued work and all the staff on making it more and more accessible and rigorous and really bridging the gap between a pure planning work and policy work, right? And how are we trying to both incorporate policy uncertainty into the planning but also using the models to help shape the policy. And I think that's where EAD sits and the Energy Assessment Division sits and CEC sits. So I just am incredibly grateful for your continued work on this.

COMMISSIONER GUNDA: A couple of formatting comments, just wanted to say. I love what's happening again with accessibility and all. Quentin, it has been raised over the last several years of just having the historical data as a part of the charts along with the forecast.

COMMISSIONER GUNDA: So just as a way to show the shape because people don't really see it, especially new people. So if you could just make sure we kind of develop that as a standard process. And also where does it start becoming a forecast along the right? Because some of our assumptions are a couple years old or last summer, whatever right. So just want to make sure that you really put that so people understand how those things are changing. Really appreciative of the seasonality model. I think that's a really helpful thing.

COMMISSIONER GUNDA: So I want to first go to slide number - sorry, I'm almost there. Okay, slide number 30, 31 and 32. Just kind of wanted to make sure that I uplift the importance of this work in terms of, I think the shapes are broadly the same. Liz, I think you mentioned, the shapes are the same, but the magnitude slightly shifted.

COMMISSIONER GUNDA: Putting on the reliability lens even a hundred megawatts during evening periods is scary to me. So just wanted to, especially in the summer, if we go back to 30, and just one more slide up to 30, we are beginning to see that, I think it's probably 3 - 400 megawatts. And then the next one is 3 - 400 megawatts. Just want us to uplift those numbers in the planning, especially as it goes to the RA and IRP. Let's just make sure we really are paying attention to those because that really changes the resource mix.

COMMISSIONER GUNDA: So along those lines, I like the idea of us using the gasoline and diesel sales as a proxy. And when we look at the quarters, right. Our current struggle on the Elk city planning kind of matches along the 7, 8, 9 months. Could you just explain to me how different the 6th month and the 10th month are, because those are uncertainties in demand electricity planning.

COMMISSIONER GUNDA: So are you seeing kind of -

Liz, is anything you can comment on, is it kind of volatile or it's really well packed those months? Six and 10, especially the shorter months is what I'm thinking.

MS. PHAM: Yeah, I'm not quite sure if I have a good answer for that. Quentin.

MR. GEE: I think maybe we could go to some different slides that might be helpful for us to maybe, I think it's backwards. A couple slides.

COMMISSIONER GUNDA: 28 I think is the one here.

MR. GEE: Yeah, there we go. Thank you. Thank you.

COMMISSIONER GUNDA: So Quentin, I think what I'm thinking is right on the electricity, especially when we focus on reliability, we are focusing six to 10. Obviously 7, 8, 9 is really important. That's the most important.

COMMISSIONER GUNDA: I'm just wondering how the six and 10 as shoulder months, how different are they? Do they closely match with 7, 8, 9 or are five and four, right? For example?

MR. GEE: We could take a closer look at that. I mean yeah, we took the averages. There are some surprising dips in months.

So here what we're looking at is the quarterly basis. I think as Liz pointed out before we took the average of these months because the data is monthly, but there is a little bit of noise in the data and we're not sure what's driving it, but there's appear to be some pretty clear dips in some months and we didn't want that to just make it too scattered.

I would say that I think, yeah, we'd have to look at the monthly inputs there, but I believe that six for light-duty is a little bit closer to July's level, but maybe not so much October's level. I think October is going down, you can see October on the light-duty going down a little bit. I think that's a well-established pattern, but I think that that six is a little bit higher and maybe six being high and I think April in particular dips a lot in light-duty. So they are canceling each other out to a certain degree. Yeah -

COMMISSIONER GUNDA: At this point, it might still be, it's still in the kind of hundreds, right. I think we're okay, but as the population goes up, I think those shoulder months are of interest for us to kind of dig into a little bit more.

MR. GEE: Okay.

COMMISSIONER GUNDA: So I just want to flag that as kind of an opportunity for us to dig into the second piece. I wanted to just make sure, I think it goes to Commissioner Monahan's comment on the hydrogen. I think hydrogen is an interesting issue in terms of policy.

COMMISSIONER GUNDA: So we can the hydrogen hub, as I think Quentin knew, what I heard from you is it's also kind of a more national policy and that might drive some of what happens in terms of interstate transport and stuff. So just wanted to see if we can run some policy sensitivities that we could use to understand. I think there's a planning component and I definitely like the way we are doing the planning, completely supportive of that. But could be run a couple of sensitivities on the price of hydrogen because as you go towards 2030 timeframes where I'm kind of beginning to struggle is we kind of caught off guard in terms of long lead time resources on the electricity planning, right?

COMMISSIONER GUNDA: Whether it's substation upgrades or distribution upgrades, whether it's interconnection challenges. We have to plan solid 5, 6, 7 years ahead of time and having those insights on what could happen based on different sensitivities of prices might be really helpful for us to think through some of the elements. So just wanted to frame that. Happy to hear any comments you might have immediately.

MR. GEE: Thanks, Vice Chair. I think that we are to a certain degree doing some of those sensitivities in Senate Bill 1075. That is not a part of the forecast but it is related to the forecast work and we did do some high hydrogen scenarios where we reduced the price of fuel cell electric trucks and we reduced the price of hydrogen. And in those results, Maggie actually was able to show that we do see higher adoption in the case of class eight trucks. There are some other issues that I think we're a little bit - with developing those scenarios under 1075 it was a little bit more just assuming just additional penetration consistent or otherwise informed by what we've seen at the Air Resources Board and the scoping plan work that they've done. But, yeah, I think those - and then also the demand scenarios work that we are going to be doing, which is a follow on to this. We will also have some high hydrogen scenarios as well. Those will be informed I think by this 1075 work that we've already done.

MR. GEE: Was there something in addition to that that you were thinking of or -

COMMISSIONER GUNDA: Yeah, thank you for putting on the record of the 1075 work and then the importance of that. I see the 1075 similar to the scoping plan and other elements, which is giving you an opportunity to think about some sensitivities and then the next question is which of those sensitivities might we want to leverage for the planning itself?

COMMISSIONER GUNDA: So I think that kind of conversation is what I'm thinking about is how do we even set up that conversation given the long lead time impacts on some of the planning issues. But I'm glad that you raised the 1075 because that's exactly where my brain was is how do you take the 1075 work and how do you implement into a planning regime that allows for enough time to actually plan and it doesn't just suddenly show up. And how do we capture that into a planning regime is where I'm going with that. So the last maybe comment but -

COMMISSIONER MONAHAN: Can I add a question onto that, Vice Chief?

COMMISSIONER GUNDA: Yeah, absolutely.

COMMISSIONER MONAHAN: I mean the hydrogen chapter of the IEPR does have this scenario and it highlights here's if hydrogen prices drop, here's the implications. Of course more hydrogen but also more electricity to generate that hydrogen and thinking through, I mean this also applies to the grid, about what's the electricity implications and we have to make some assumptions about how much of that hydrogen is being produced here versus other places here in California. But it is an interesting idea to think more about should their in the demand forecast be this kind of low hydrogen price scenario. What it means if all the, it would kind of be, I don't know it would be the high electricity case. It's unlikely that all the hydrogen is going to be produced here in the state of California. And we're kind of pushing the boundaries about what we think. If the price of hydrogen got down to $5 a kilogram, what does that mean? And it's kind of transformational I would say on the transportation side, but how that gets integrated with the demand forecast, whether there should be this kind of extreme case. I'd be curious about what your thoughts vice chair, does that make sense?

COMMISSIONER GUNDA: Yeah. Commissioner Monahan, I'm just kind of thinking through this in the discussion of some of the comments we heard around the three pillars. Or some of the conversations we've heard in SB 100 and the change of regime in SB 100 too because SB 100 in the previous discussions just assumed it's going to be all the green hydrogen produced in California is going to come from onsite generation.

COMMISSIONER GUNDA: And, to your point, this could have incredible implications on good reliability and even having the necessary systems in place for wires. So I kind of lean towards safeguarding our work to include those impacts sooner than later, even if they're marginal. And if we feel uncomfortable because we don't really - there's too many uncertainties at least putting that as a part of forecast to say here's kind of - I think to Commissioner Monahan's point, what you might lose in electric charging of the trucks will still be impacting on hydrogen production.

COMMISSIONER GUNDA: I mean in the end you might actually have the same demand, not that. So if I'm hearing Commissioner Monahan's perspective, too, I think we are in alignment to think about at a minimum how are we going to have this conversation on an ongoing basis, at a minimum. And when is the right time to incorporate those elements into the grid planning.

COMMISSIONER GUNDA: Two, I mean a likely slightly higher level, is there a minimum amount we can begin to bake in on the grid impacts? That seems reasonable. That doesn't push us over because we have to think about the rate impacts and the feasibility of actually building, but I just wanted to put that on the team. You know, by the time we adopt this, having something along those lines would be helpful. A tier system of approach.

Mr GEE: Yeah, I definitely agree both points. Commissioner Monahan and Vice Chair. Yeah, I think as Commissioner Monahan pointed out, the truly high electrification case will be the high hydrogen case if we're going to produce hydrogen from electrolysis, which seems to be the only scalable - I don't want to speculate too much, but it appears to be one of the only scalable approaches to getting hydrogen at those levels. I think there are some interesting questions.

So right now we just evaluate the hydrogen demand. We're not really thinking about where or the fuel demand actually we don't - in our work here, at least, work on these other issues about fuel demand, gasoline demand, those kinds of things. We don't really think a lot about the supply issues around supply of - at least for our forecasting work, we don't think about where does the gasoline come from, where does the electricity come from?

We just kind of say we need this many gallons need this many kilowatt hours. And so similarly we say we would need or we expect to be demand that there's this much demand for hydrogen kilogram, kilograms of hydrogen.

I think probably what we would want to do, and need to talk more with the rest of the demand forecasters, is where would this come into play? It might come into play at the industrial level, but there's also some important questions about what's going to be the cheapest approach to generating hydrogen because your levelized cost of hydrogen could be quite low if you go completely offsite, you build your little solar location. It's not tied to the grid and you run your electrolyzers there because you don't have to worry about transmission distribution costs or other - you're kind of vertically integrating your production process there. So that might be one pathway.

The other pathway is to tie yourself into the grid, maybe try to generate it on site or those sorts of things. Definitely a lot of questions to get at there and we're not really sure where the market's headed. I mean the hydrogen hub I think is going to be really helpful for us to learn about where we would be going. But yeah, we're going to continue to have those conversations throughout. Or begin the conversations I think in deeper, at a deeper level and continue to monitor where we're headed in the market with that. Because hydrogen's a particularly useful point because it then becomes a source of demand and is an issue, of electricity demand. So we do need to really think that through. Might be something to be done in the industrial area or we might need a whole new segment, but certainly a critical point as we see developments and if we can get the levelized cost of hydrogen down, then we probably will see more uptake in the transportation sector and need to be aware of the electricity system impacts.

COMMISSIONER GUNDA: Yes, I mean - by the way, I'm really glad we baked in some time because I feel like there is so much opportunity to have these conversations in a public setting so people can then react. And we get some information and having a conversation flowing because I think the more we are able to set the stage for stakeholder input, the better it is. So thank you Quentin for, and

Heather, for kind of baking this time.

COMMISSIONER GUNDA: I have two thoughts. I just frame it and then I'll defer to Commissioner Monahan and Heather next steps here in the morning session. So I'm looking at slides again. Incredible work on the regional disaggregation. Thank you for that work and the thoughts that's going in there. Couple of pieces on that. When we talk about the regional disaggregation, Liz, I think the 12.5 percent allocation also on the end route, so there's two elements, right? So the regional disaggregation that Maggie presented and then you presented on the regional allocation.

COMMISSIONER GUNDA: Could we just expand on that a little bit on the basis of the assumptions? Like, how are we specifically looking at - what's the data that's driving the assumption, let's say on the 12.5 percent. And,, Maggie on your side in the regional disaggregation, I wonder who presented that. I apologize if it was both Liz, just how are we, what assumptions are actually driving our thinking around that?

MR. GEE: Yeah, or Liz -

MS. PHAM: Actually Quentin, can you take this?

MR. GEE: Sure. Yeah. So really it's DCFC charging on highway corridors I think is a particular challenge for us because sometimes people will just, as you could imagine, someone you might fill up at the local gas station that's near the highway and you're just driving in town all the time. A similar effect could be seen there as well.

So what we did is we used - we used the EVI PRO or the EVI road trip tool that is used in 2127, actually helps inform some of the work that we are some of the work that we did here and I think they had about 10 percent, maybe 12 percent or so. And we just decided that just to be safe, we would add that in. I should stress here that we're not sort of adding additional load. We're sort of redistributing the load regionally. And one of the reasons why we noticed this problem was because there's an additional product that comes after the IEPR called the Load Bus Allocation.

And one of the big problems that we ran into with that was that we conserved electricity within different forecasting zones. And forecasting zones in the northern part of the state and other rural areas didn't have enough gigawatt hours available to them to account for potential road trips. And so we used the road trip as the EVI road trip baseline 10 percent, 12.5 percent or so of demand. We pulled that out of everywhere and redistributed it back. And a lot of forecasting zones got their load, got a lot of that load back. So we're not saying it all goes into rural areas or something like that, but it was just something that will allow us to conduct better work on our load bus allocation. And we think also it will help the IOUs plan a little bit better because the IOUs that do have a lot more urban density, we are anticipating this still will be a lot of DCFC charging there. But we're not anticipating quite as much of that compared to some of the other areas that maybe have a little bit more highway traffic or highway only traffic. Does that get at the question?

COMMISSIONER GUNDA: Yeah, it does. And here's a suggestion and I think at least a recommendation for us to think through, we do have those 10,000 gas stations of data that we gather and I think looking at the potential gasoline consumption, I don't know if we have that level of disaggregated information and maybe it's not indicative of exactly what the patterns are. Just want to uplift that dataset we have and see if there is an opportunity to dig into some trend analysis on that as we think through next year.

COMMISSIONER GUNDA: I just want to flag that as an opportunity because I'm beginning to see the equity intersection here both on electrification but also air quality in opportunity. So just want to uplift that conversation to think about.

COMMISSIONER GUNDA: And before I hand off, Maggie, I apologize. I was driving when I heard the first set so I didn't really know who slides or what, but that's why I was calling you on some of this. But thank you so much. This is great and I'll pass it back to Commissioner Monahan.

COMMISSIONER MONAHAN: Well I had a question about, well I think you guys know I convened the ports collaborative. We meet about quarterly and the ports are of course huge loads as you're off-road data indicated. And they're also very interested in hydrogen. I think for a lot of this off-road equipment that's going to be a point of intersection, maybe much more willing to pay a higher price for some of the performance characteristics that they see with hydrogen. So I think there's a lot of modeling in the off-road sector, especially specific to ports that is interesting and maybe somewhat unique in terms of the huge load.

COMMISSIONER MONAHAN: And can you talk about how you're thinking about these single - maybe ports and specifically because I think they are pretty specific use case, but data centers are somewhat similar in terms of a huge load to the grid and how are we thinking about any analysis specific to, let's just start with ports -

COMMISSIONER GUNDA: Before you jump in. Can I just add a couple points to Commissioner Monahan just as you think through.

COMMISSIONER GUNDA: I think when you were talking about offload and I wanted to wait until the second half of today to ask about a couple of intersecting questions there. The transportation element touches other sectors now, so the offload kind of touches the ports and ag and we got a lot of interest from the ag sector on thinking through how to support ag electrification and such. So I think just uplifting Commissioner Monahan's question through the broader lens. And also the uncertainties of future economic growth or technology. Especially as we think about data centers with AI. We've heard a 10 x growth in Bay Area, for example. One 30,000 foot level. How are you thinking about that and more specifically Commissioner Monahan's point on ports and ag?

MR. GEE: Yeah, great question. I would say I think you probably want to have the Demand Analysis Branch touch more on the issue of servers and those sorts of issues that tie into there. But that is, I mean servers, cannabis, these other issues are really - they can be big sources of demand and that's something that they're going to be working on.

When it comes to the transportation side of things, definitely there are these kind of weird - when we think of transportation, we think of people trying to get somewhere, but there are these important questions around moving stuff around a defined location like at a port or at an agricultural site.

So the off-road model right now we do have some kind of baseline population data around the vehicles that are operating at these sites already. So we have sort of a baseline population of how many, what are they called, rubber tire gantry lifters, they lift up a shipping container.

There are also other devices that are a little bit more mobile. So there's all kinds of different devices that currently use a lot of combustion power. And we're anticipating the off-road model anticipates growth or penetration of electric into that.

One of the things we definitely need to make sure that we're doing in the long run is finding a way to integrate in hydrogen into that model and coming up with feasible options there. Because right now we assume that in lieu of combustion fuels it moves over to electricity. But as Commissioner Monahan pointed out earlier, and I think we had at the SB 1075 workshop, we had a discussion about how some of the ports are looking into hydrogen as well.

If one of the reasons why - so the reasons might be associated with the performance issues. Hydrogen, it can be much faster to refuel. You don't have heavy batteries in some of these devices or in some of these vehicles so you can get a lot more bang for your buck or bang for your kilogram of weight that's added onto the device. So that's an important consideration there. But I think a lot of it is going to come from the fact that they're concerned about electricity loads as well. And, again, so onsite electrolysis for hydrogen production would actually add more load because of the round trip efficiency that is you need a hundred units of electricity could get you like 90 ish units of movement in a battery electric car, a vehicle. A hundred units of electricity through electrolysis, through a fuel cell, et cetera is only going to get you about maybe 40, 50, maybe a little bit more units of movement or energy units of movement there.

So probably the ports are going to need to be getting the hydrogen offsite if they're worried about the grid constraints on the site.

But yeah, there's a lot of shore power actually already going on. And shore power is the largest thing at the ports. There's a lot of shore power already going on, but there is a rapid requirement for 2027 for most of the shore power adoption there. So no running your engines and burning bunker fuel or whatever at the port. And then there's also that equipment there, the cargo handling equipment. Those, we do anticipate a lot of load there. I think there's a little bit of disagreement from what we're hearing from some sources versus others about what the assumptions should be about what the load is going to be from some of those devices. We probably shouldn't be assuming that these things are going to be operating at full power 100 percent of the time. So we have to come up with scenarios and say, okay, well these things stop. They move around, they park people take breaks. There's all kinds of other activities that occur to where we don't want to say that things are going to be operating at full capacity. We want to make sure analysis doesn't assume that.

COMMISSIONER MONAHAN: Is it possible, Quentin, that we would get to a place where we could disaggregate results by port?

MR. GEE: Yeah, I think that's actually going to be our goal. One of the things that are, so again, I constantly talk about the load bus allocation, but this is kind of our new thing that transportation has been a part of in the last year or so, year and a half, two years. We do aggregate. We are beginning to think about load more geographically speaking. And this year I think with the load bus allocation, I think I mentioned before, the off-road model, that big sort of donut that I showed with all that load. That right now goes just into the baseline forecast and it's just built into all the system load that the demand analysis branch focuses on. But what we want to do with the load bus allocation is at least pull the port out, the port stuff, the shore power and the cargo handling equipment.

And then also maybe, I'm not quite sure what we can do at the early stages now, but maybe do that with ag this year. We're not quite sure yet what can be done. But we probably need to then just find which substation or maybe there's two, are tied to each port and come up with a plausible way to allocate the load to those facilities. So yeah, that's something that we will be working on this year with our load bus allocation. It still will go into the baseline forecast in terms of the overall CAISO load shape and the utility load shapes or load profiles that we see. But, yeah, we do want to I think build that in as an option for saying, Hey, yeah, these ports also are going to be experiencing some additional load here that you might not have expected. It's not as big as medium and heavy duty. If you look at it, it's about, I think it adds up to 1500 or so gigawatt hours for ports in 2035, whereas freight is closer to 12,000 gigawatt hours or 11,000 gigawatt hours. So it's not as large, but it's very concentrated in a few select locations. And a similar thing with ag, it's very constant, so ag is not that large either, but it also is very concentrated in a few key points. And those are also areas in ag where there's not necessarily a whole ton of capacity in fairly isolated locations.

COMMISSIONER MONAHAN: That's great to hear, Quentin. It's really exciting that you're moving - the team is moving towards that approach. And I know the ports are really interested in this, so we could even have a sample port and they have a list of all the equipment that they're planning to electrify and it would be interesting at some point to work with one specific port and really triangulate what our demand forecast is, finding, what their own analysis and see if we can come up with deeper analysis for each of the ports. And I think they're so important for goods movement. They're also going to be so important when it comes to offshore wind development. And that's going to be its own special set of analytical products that we're working of course to support from another angle, but I think it's a great evolution.

COMMISSIONER GUNDA: One comment on that thought, I think Quentin and I, this is where the lines between the demand forecasting, demand scenarios, DER and supply, everything's kind of blurring with the work we are doing right now. And also it's blurring between the policy and planning, right? It's like we're in this interesting phase, which creates opportunities for such good work and we can dig in.

COMMISSIONER GUNDA: So couple of things, the busbar allocation and the port electrification and I would just say port electrification and broader decarbonization and so tied to the supply side analysis on which power plants can you retire in those load pockets. The transmission potential transmission constraints. So I really would like to continue to support the work you're doing on the demand office is doing on the overall disaggregation of busbar loads.

COMMISSIONER GUNDA: I want to just think through a couple of elements data needs. Are we at a place where is there a threshold for us to go back and update our data regulations? Which ones do we want? I mean, I don't want to do regulations for the sake of regulations. If we can get it through supply forms, that's great. But is there an opportunity there? Two, the DER work that PUC has done last this year with the contracts like Kavala and such who have been also adopting different analyses for distribution level planning. And I know IOUs are looking at it too, for their own work.

COMMISSIONER GUNDA: Is there a way to uplift the conversation on the way the load is happening at large and how do we continue to make incremental but valuable improvements to forecast to support that conversation? So we don't necessarily have to duplicate, but if we can leverage other elements of work that's been done, that's probably also another way to approach it.

COMMISSIONER GUNDA: But tremendous work, team. Liz, Maggie, just really good presentations. The way you approach the presentations is awesome. Thanks, Quentin. And thanks to the entire forecasting team. I have no further questions. Thank you.

COMMISSIONER MONAHAN: And I don't either, but it's been such a pleasure to have this conversation. It's nice to be able to, with Vice Chair Gunda, be able to muse on these issues and really it's such impressive work. I just can't even tell you to see the change over the last four years has just been amazing. And a lot of this has to do with the fact that transportation electrification is becoming so much more of an important aspect of our demand forecast. So just thanks to you Quentin, and to the whole team, really just amazing work.

MR. GEE: Great. Thanks both of you.

MS. RAITT: Beautiful. Thank you. We have one question from an attendee and Heidi Javanhakht is available to go through that with us. So go ahead Heidi.

MS. JAVANBAKHT: Hi. Good morning, everyone. So we do have one question in the A and A from Robert Perry from Synergistic Solutions.

MS. JAVANBAKHT: So his question is, one unmentioned aspect concerns the fact that vehicle charging refueling is critical infrastructure requiring a minimum level of energy resilience that can only be delivered with onsite adjacent distributed generation / hydrogen production. Are any resilience considerations being considered in calculating load modifier scenarios?

MR. GEE: Yeah. Thanks, Robert, for your question. I think what I would say here is that we conduct forecasting very much at a system level. I think we saw on Liz's maps, on her slides, we break the state into about 20 forecasting zones. The utilities make up the bulk of those.

I would say overall, we really don't think at that very, very close sort of site level resilience consideration. Those are important aspects of ensuring that we have reliable access. I can imagine people being concerned about things like public safety power shutoffs, et cetera, but we're really sort of evaluating the forecast at this level where we're trying to think about system planning, distribution planning, and informing transmission planning. Certainly there are critical components there, but that's a little bit outside of where we focus, but definitely an issue for concern when we start thinking about those site level challenges.

MS. RAITT: I think that's all the questions from the audience.

And so thank you so much Liz and Quentin and Maggie again and Commissioners for that really great conversation and presentations this morning.

So we are done with our morning part of the workshop unless Commissioners if you wanted to make any remarks. Otherwise we can break for lunch. Okay.

So we'll be back here at one o'clock and we'll start, we'll go ahead and keep this open, but we'll stop recording for the lunch break and resume back at one o'clock. Look forward to seeing everyone. Thanks.

(OFF THE RECORD AT 11:39 a.m.)

(ON THE RECORD AT 1:01 p.m.)

MS. RAITT: All right, welcome back everybody for our afternoon session on this IEPR workshop. So we'll go ahead and jump in in the afternoon and hear about additional achievable scenario results for energy efficiency and the fuel substitution. And so Vice Chair Gunda, did you, I think you said you didn't or maybe Commissioner Monahan, did you want to make any remarks? I know you just told me and I can't remember what you said. Sorry.

COMMISSIONER MONAHAN: I think the vice chair is going to be leading this since he's deep in the weeds on this and I'm going to be having to leave pretty soon actually for another event.

MS. RAITT: Okay, thanks.

VICE CHAIR GUNDA: Thank you, Heather. You always check on me so that's good. Yes, thank you all and welcome back everybody. I think I just wanted to say thanks to the transportation team this morning. It was a really good conversation on both the elements that the transportation team is able to implement to enhance the forecasting for not only planning purposes but also policy options and discussion. And then I believe we had some robust discussion on some additional refinements we could continue to foster in the forecasting.

And this afternoon I think is another important element, specifically the additional achievable energy efficiency, achievable fuel substitution and behind the meter generation forecast and storage, which are all teeing up the conversation on the building decarbonization. So without further, without any further delay, I would just pass it on to Ingrid Neumann to kick us off with the additional achievable energy efficiency and fuel substitution results. Thanks.

MS. NEUMANN: Alright, here we go. Let's move on to the title slide. There we go.

Good afternoon, Commissioners and stakeholders. My name is Ingrid Neumann and I'm presenting the results for Additional Achievable Energy Efficiency, AAEE, and the programmatic portion of Additional Achievable Fuel Substitution, AAFS, for the 2023 IEPR cycle. Next slide, please.

So the objective of these two load modifiers is to continue to focus on firm programs and projections. Since the core scenarios will be used for planning and procurement purposes. As in previous iterations, staff has developed variations around these most probable futures to show other possible outcomes given less or more effort and ability to realize the potential of existing or proposed energy efficiency and fuel substitution programs. As developed in 2021, AAFS continues to be conceptualized separately from AAEE. Next slide, please.

Any overlap between these load modifiers, as well as any potential overlap with the load modifiers in the baseline energy demand forecast are accounted for and removed. Only achievable energy efficiency savings or fuel substitution impacts above and beyond what is already incorporated in the baseline energy consumption forecasts are retained in the load modifiers. Both AAEE and AAFS reduce gas consumption while AAEE also reduces electricity consumption, AAFS increases it. Thus we call AAEE savings and AAFS impacts. Both load modifier increments and decrements are relative to the baseline electricity and gas consumption on an annual basis. Electricity consumption is also modified by both AAEE and AAFS on an hourly basis. AAFS may contain both programmatic inputs, which I'll be discussing in my presentation, as well as technology-based fuel substitution modeled by our fuel substitution scenario analysis tool, which will be described in subsequent presentations by my colleagues Nicholas Janusch and Ethan Cooper. Next slide, please.

So when we design the scenarios, our general approach is to start at the bottom and build Upworks. We start from conservative in scenario one at the bottom in red and go up to more optimistic or aggressive scenarios. So here the red and orange are conservative and would be the minimum impacts expected to occur. Sometimes that might include firm commitments, so existing programs or standards that are not yet incorporated in the baseline forecast and then some newly existing programs. Now for three and four, three being in green - scenario three, that's our reference scenario. It's something that we like to call reasonably expected to occur. So it's something where there's still uncertainty, of course, around these newly developed and funded programs, but they are expected to occur in some shape. Then there's a "blue skies" or slightly optimistic version of that scenario here in blue, number four. And the green and blue scenarios are the ones that are used for the forecast load modifiers.

Moving on to the next slide, please.

We have the more "blue skies," or more optimistic, are aggressive scenarios in darker blue number five and violet and number six, that are policy focused. So these really ratchet up, add more speculative programs. These might meet some 2030 SB 350 doubling goals or other mid-century type goals once we've ratcheted everything up to the possible and the most optimistic view of what's possible for energy efficiency and fuel substitution given current knowledge. So those are not used for the forecast, just three and four and for energy efficiency too. So we'll go into that in a second. Next slide, please.

So first, some general things that were developed for the programmatic pieces of AAFS and AAEE in the 2023 IEPR cycle. We have utilized, updated and enhanced versions of the savings, accounting, aggregation and extrapolation methodology - methodology and tools previously employed for 2021. Historical data, of course, was updated and then the potential savings projections were updated based on that in all the existing workbooks. New workbooks were added based on recent programmatic activities in the last two years. And we added some capability to the tool. So we have building type disaggregation and can output by forecast zone, not just by utility.

There was an addition of some basic cost calculations for each scenario so that the value of various energy efficiency and fuel impacts can begin to be quantified for later work this year and next year. And then we also enhanced the input data as well as the software tools to allow for better extrapolation of potential savings to mid-century and, again, that supports some future work as well as extrapolation to the forecast period. This forecast goes from 2024 to 2040 and some of our input data doesn't reach all the way out to 2040. So we do need to do some extrapolation there. Next slide, please.

So we also have a more robust analysis of beyond utility programs. So these are the programs that are not run by IOUs or POUs and not reported by them, than those that were originally evaluated in the 2021 IEPR, such as the technology and equipment for clean heating or tech program as well as consideration of additional programs not included in the 2021 IEPR because those had not quite been conceived of yet. Next slide, please.

So we also reworked our Title 24 Analysis. The Title 24 Building Energy Efficiency Standard Analysis is now based directly on measures at the sector and segment level. This measure based analysis can then be rolled forward as specific measures are likely to be adopted for future code cycles. So we know what was adopted for the

2022 code cycle, where we might see some impacts from that this year and more next, but the 2025 are proposed and then we can speculate as to what the future code cycles can look like after that.

So that's more precise and updated than the original percent better than approach that was originally developed in support of SB 350 tracking and projections. We also updated the compliance pathway most likely to be chosen by builders to meet the 2022 Title 24 requirements. That was the first time that the options included either enhanced efficiency measures via performance calculation or electrification of one of the end uses based on climate zone, so either space or water heating. And so there's an electrification component there and some of the assumptions that went in there as to what builders might choose was updated based on new information. Next slide, please.

We also added some new workbooks that are listed here. The really important ones would be equitable electrification and so that's California-funded as well as the Clean Energy Reliability Investment Plan is also California-funded. It's a little bit less clear as to how much of that might go to demand site objectification, but some of those enabling technologies would likely allow for additional electrification. So that small contribution was estimated now, but the equitable electrification has two components, a direct install and incentive piece, and both of those are expected to have significant impacts. Could be as early as 2025, maybe 2026 or 2027 either if we looked at this very conservatively, but it'll certainly have significant impacts there. Same thing for the Inflation Reduction Act. The IRA funding come - coming from the federal government. There are two programs there HEEHRA, a High Efficiency Electric Home Rebate Act and that might be bundled with or be applied in a similar way as the Equitable Building Decarbonization Incentive Program. And then separately the IRA funded whole-house Homeowner Managed Energy Savings or HOMES program is an energy efficiency retrofit program. Then we updated some locally targeted electrification impacts like we've had local government ordinances, but we've added some geographic aggregation to those that's actually showing where those impacts are more likely to occur as well as added many new local ordinances that have been developed since 2021, and a few load serving entity decarbonization programs are included there as well. Next slide, please.

All right, so we would build up our scenarios and the scenarios mostly - at least the ones that we're using for forecasting would include all of these elements at various levels. So for the IOU programs, we rely on the CPUC's potential goal study as well as IOU data captured in

CEDARS on more recent fuel substitution activities. Then that is something that's updated every two years, the CPUC'S potential end goal study. So it really is the most recent vintage of that study. The CMUA, which supports the POUs and where we get our POU energy efficiency program forecast from is updated every four years.

So we would still be using the one that we received in 2021. That doesn't include fuel substitutions. So we did that separately after conversations with the POUs in 2021, and we've made some updates to that based on subsequent conversations, which basically we'll look at the data when we get there. So then we also include some future title 20 and federal appliance standards that aren't included yet in the baseline forecast. And for this time around the 2022 and future building standards as well. Next slide.

So that's the bulk of what goes in. And then we have a plethora of other programs that operate outside of the utility energy efficiency portfolios. And that's what we've kind of bundled as the beyond utility. And there's a collection of traditional energy efficiency programs where we've updated the data but they've fundamentally not changed since 2021, other than having more historic data honing in on that.

Then the build and tech programs that are run as per SB 1477, those were included for the first time in 2021, but we separated those because we actually do have two years of historical data now for tech and we redid that modeling to reflect that. Then we added workbooks on the California Electric HOMES program, the Wildlife Natural Disaster Resiliency Rebuild Program, which allows for electrified homes to be rebuilt in areas affected by fires and such, as well as the affordable housing and sustainability community programs. The portions or their phases that have focused on electrification. So the last phase had mostly electrification and then those most recent phase where they just closed, I want to say bids but that doesn't feel like quite the right word, but they just took the solicitations for those and the impacts will be seen in the next few years. So then, of course, the IRA funded hura and homes as well as equability decarbonization direct and install and incentive programs and the piece of syrup that might contribute to electrification. Next slide, please.

Then lastly, local ordinances encouraging electrification of some or all end uses as well as other target electrification including local natural gas bans. Then the last bullet here is not something that's included in the programmatic piece, but it is included in AAFS.

So we do the zero emissions appliance technology characterization and that's modeled by the FSSAT and that includes CARB's state implementation plan, but you'll have to wait for the presentations after mine to get the details on those. So next slide, please.

So this is the spectrum from red to violet here of the scenarios that were developed for electricity, AAEE savings and AAFS incremental impacts. You can see that the AAEE values are all negative. Those are savings from the baseline. They start from a small modest amount in red going to a very optimistic scenario six and violet. And, similarly but in reverse, for the electrification, the more electrification we have, we do add a small amount of electricity. We hope that it's efficient electrification and the programmatic electrification is efficient. They wouldn't incentivize it otherwise. So that really does show you the range of scenarios that we're looking at in total. Now those are not all being considered for the forecast. So let's go to the next slide and look at gas, same kind of spread but both AAEE and AAFS reduce gas consumption. Alright, let's go to the next slide.

So now we're focusing on the two scenarios that are used for the forecast. In green, the statewide planning scenario. So this is AAEE, so energy efficiency, electricity saved on the top, gas saved on the bottom, the dotted lines and the open circles reflect the 2021 IEPR vintage forecast. And the 2023 IEPR vintage forecast is shown in solid lines, in solid dots. So the most noticeable thing here is that the extrapolation things really change in 2030. It's less optimistic based on more recent data and updated modeling. In 2021, we only did the forecast out to 2035 and there was a lot of extrapolation after 2028, 2029, 2030. And we have updated data that informed a better extrapolation this time around.

So on the next slide we have the same type of comparison for the AAFS, the fuel substitution piece and there, so for electricity, a AAEE 3 and AAFS 3 were both used for the planning forecast and then I don't mean to say for electricity, but for the planning forecast, a AAEE 3 and AAFS 3 are used and for the local reliability scenario in blue it's AAEE 2, so that's more conservative, so less energy efficiency and more agive fuel substitution AAFS 4.

So that's a little bit more electricity being added. So we're definitely calling it conservative from an electricity or electric grid standpoint here. And what we can see here is that in the 2023 vintage, the AAFS forecast and extrapolation plus 2030 as affected more than AAEE was, and that's really due to the consideration of carb state implementation plan in most of the data streams. The state implementation plan was adopted in September of 2022 by carb. So this was after the 2021 programmatic or the 2021 IEPR vintages of AAEE and AAFS were developed and CARB just started rulemaking on that in May of this year. So Ethan Cooper will give you more information on that, but it's important to recognize that there is a drop off of impacts here from the programmatic AAFS, but some of that will be seen then in the SIP modeling or other zero emissions standards modeling from the FSOT.

So it's not necessarily gone. Then what we'll also see when we look at the breakdown a little bit as far as the four main data streams is that the beyond utility, which includes the IRA funded and equitable building decarbonization programs. Those actually grow a bit. So we really don't see that drop off in the AAFS 4, or the blue local reliability scenario, which is looking at the reference case of those. Whereas in the green, we're looking at a more conservative version of those. But then it does drop off in the long term like after 2035 because that's when those programs expire and the first year savings for those will cease unless they're somehow re-upped. So next slide, please.

So this is our process flow overview diagram for the data integration tool. Kind of shows us the four big data streams. We have the CMUA's PG study that gives us the POU projections. The one that we received in 2021 did include projections out to 2041. So we didn't have to do any extrapolation there ourselves. Then with the 2023

CPUC's potential end goal study for the IU programmatic projections, that went out to 2034. So we did work with the CPUC team on extrapolating that to 2040. And then for codes and standards and the rest of the beyond utility, those we extrapolate ourselves in the beyond utility workbooks that are managed by the Energy Commission. So then the data integration tool takes all those pieces together, makes the parts cumulative that aren't yet so that we end up with cumulative Additional Achievable Energy Efficiency and fuel substitution projections for each year starting in 2024 out to 2040. That can be presented by utility or forecast zone, of course it can be bundled to planning area or attack. And then sector now building type end use and scenario. Then we have an hourly tool for the electricity portion where we can apply 8760 load shapes by end use and sector to the annual values to obtain the hourly values for each year at that same level of disaggregation. Next slide, please.

So for the planning scenario. Now we have it, I was going to say black on white, but it's green on white, right? Because we were color coding it green for the planning scenario. We're looking at the reference case of AAEE 3 and the reference scenario for AAFS 3. So this is reasonable to occur but with greater uncertainty about penetrations and volume of impact. And we do include newly developed and funded programs.

So we have the IOU programs, the POU programs, the Title 24, we include the 2022 standards at reference. Those are happening, those are active. Then the proposed Title 24, 2025 vintage at a conservative level and some of the Title 20 and federal appliance standards that may occur in the near term future in a conservative view. Next slide.

So then we have the following programs in a reference modeling view. Tech, right? That's existing. We have two viewers of data on that, the targeted electrification, a lot of the other ones that we had in 2021 as well and the other ones that are pretty well understood. Then we have the beyond utility programs that are included in a conservative modeling view on the right hand side. And those include ones where some like the top three asset rating, smart meter, s-ship heat pump, water heating and the FPIP. Those have been around but there's still a fair amount of uncertainty about the impacts there. So we keep that at a conservative level. And then, of course, we have the new programs which are not all fully designed. There's some proposals going out, there's draft for the equitable building decarbonization program, direct install programs, comments coming in on those.

So those are still being sorted out, but the funding is there. And they will occur in some way and I expect it to have some decent sized impacts.

So let's move on to the next slide. So now we're looking at the local reliability scenario. So we do look at a little bit more of a blue skies version of the green reference case. So we do look at AAFS 4 there. We take the potential goal study scenario, so not the one that was decided on upon the goal. That's the one we use for the reference, but we take something where there's a little bit more fuel substitution there. And it turns out that the modeling actually changes between, there's a break point there and there's no way to hybridize that. So there's a fairly good gap between what's in AAFS 3 and 4 for IOU programs at least.

Then the other ones are a little smoother. We include Title 24 standards, which include that compliance pathway via electrification, right. That's proposed in 2025 and we expect something similar to be proposed at a higher level in 2028 and we take a conservative view of what might be proposed thereafter talking to subject matter experts. So then we include everything that was included in AAFS 3, but we take a more reference view, we're less conservative about the viewpoint that we take. And really what that means for the equitable building programs and the IRA funded programs is expecting that impacts might occur sooner rather than later. And that the impacts are also greater per dollar spent. Maybe you can spend 15 percent for administration, but then how much of the remainder is spent on what type of measures versus upgrading panels and things like that where you don't get a direct impact.

So taking a little bit more of a reference view of that instead of a conservative view like we did in a AAFS 3. So next slide, please.

So then we have the AAEE 2 went back to orange, right? Because we went from our scenarios, we built them up like the rainbow, the spectrum of colors are red, orange, yellow, but we didn't do yellow. That one's hard to see. So red, orange, green, blue, more blue and violet. And we're trying to stay in that green / blue area except where we're really looking at a conservative picture for local reliability where we want to kind of pull back on the energy efficiencies and that's always been agreed upon with the electricity planning agencies.

So for the AAEE 2, it really is just pulling back, looking at something slightly less than the goals scenario used in the reference taking a scaled back view of POU programs, taking a conservative view of the current Title 24, 2022 vintage and so on. Taking out some programs and leaving the ones that were still included and looking at them a little bit more conservatively.

So let's move on to the next slide and look at some data. So we have these sort of wedges, they look like wedges, but the extrapolation, it can't be linear anymore. It's not what the data is showing. We have here on the right hand side the electricity and gas savings for scenario AAEE 3 for 2023. The three sort of wedges, if you will, are in blue, the IOU programs in green, the POU programs in purple, the codes and standards and in red the beyond utility. So we can see if we compare to the next slide, what we had in 2021 that the purple codes and standards seems to have shrunk a lot and that's not because anything bad happened really, they're still having that energy efficiency. It's just there were a of appliance standards in 2021 that were still included in the load modifier and that had now being captured in the baseline forecast and the rest of the pieces remain fairly stable.

If we look at the blue and the green and the red, those sizes haven't changed so much. I mean the IOU savings have dropped a little bit, but nothing like they had in the previous two vintages of the IEPR. So let's go ahead and move to the next slide and look at AAFS 3.

So that's our reference scenario for fuel substitution that's used for the planning scenario and it does look awfully small, right? It's not a pretty picture to look at. There's a reason behind that. We wanted to put it on the same scale as what we had in 2021. So that's already letting you know that what we estimated in 2021 in the first cut of AAFS was greater than what we're finding in 2023. So let's go ahead to the next slide.

And we would say that really the biggest difference here is that the IOU program - programmatic impacts drop after 2030 due to the potential end goal study considering the CARB's state implementation being active at that time.

So that's the blue piece here. It drops significantly. And there are really two reasons for that. So you see, well that also happens before 2030. So yes, after 2030 we can say everybody's considering the SIP plan, which we didn't consider in 2021, but before that the modeling was simply different even before 2030. The values are smaller due to calibration to actual electrification program performance now in 2023 that we have two years of data for. Previously in 2021, we only had small samples of unevaluated pilot program data. And the PG study, for example, was directly calibrated to the more mature energy efficiency programs. And, I mean, we knew that there were more mature, but we didn't know that the difference was going to come out like this. So we did update the modeling for 2023 that may also affect the POU programs in the future. We did have some conversations with some POUs and we did adjust that green wedge based on those.

They didn't roll out some of the programs as soon as they expected, but they're still planning on doing those programs. So those first year savings were pushed outwards. So it was basically they're just delayed a little bit. So the total cumulative value in the out years will be slightly less. Then for a lot of other things. We also considered that the State Implementation Plan after 2030 would not allow incentivizing pure electrification. You'd have to incentivize even higher levels of efficiency for that type of electrification and then quibble about where that might end up. But in a great part - some of this is going to be all of these updates in 2023 are based on two years of electrification data that we didn't have in 2021 and the impending SIP. So we do really allow for fewer programmatic AAFS impacts in the forecast. But some of these impacts are of course then recouped by the FSSAT modeling of the state implementation plan, which my colleagues Nick and Ethan will discuss in the subsequent presentations. So let's move on to the local reliability scenario.

This is the data for AAEE 2. So the slightly more conservative energy efficiency scenario and really the trends are very similar as for AAEE 3. Nothing dramatic here. Let's go to the next slide.

Compare that to what we had in 2021. It's mainly the extrapolation that's changed in some of the codes and standards went into that baseline there.

Let's move on to the AAFS 4 scenario used for the local reliability scenario. Here we can perhaps see the impacts of the IOU programs taking the SIP into account a little bit better. We see that blue wedge or chunk really change around 2029, 2030. It starts dropping. And same thing with the codes and standards. They're meeting their technical limits on electrification in new construction at some point. So the first year impacts won't be seen too long after 2030.

But then the IRA and equitable building decarbonization do grow, at least during the time that they're funded. But then past 2035, they start dropping. They start dropping off. I think most of the funding the first year should go through about 2032 for most of these programs. But then unless they're extended, we would just see those cumulative values decay.

So in the next slide we can compare that to what we had in 2021 and it's not - the difference isn't as big for AAFS 4 as it was for AAFS 3, but it follows the same trends for the exact same reasons. So let's move on.

Right, okay, so this should help us segue into Nick's presentation about some of the way that we're treating the state Home Implementation Plan, other zero emissions standards. But really kind of clarifying, just like Quentin said earlier this morning, these load modifiers, they go through a whole refresh every what I like to call a full IEPR cycle, which is every odd year. So in 2021 we developed the six AAEE scenarios. And it was the first time that we developed explicit AAFS scenarios. And then there was the statewide planning forecast, which included AAEE 3, AAFS 3, just like it does now. And the local reliability scenario AAEE 2, AAFS 4 and in some way just like it does now, except now what goes into AAFS is more.

So what happened, next slide, in 2022 was the adoption of the sip and we knew that that would have a pretty big impact on the electricity forecast. So we took a first stab at putting that into the forecast and did so in the local reliability scenario. So we didn't update any of the programmatic pieces. So all the pieces I talked about today and showed you on left side comparing the 2021 vintage to the 2023 vintage, those were only programmatic pieces, but then in 2022 we added that FSAP modeling of the SIP on top of AAFS 4 for that local reliability scenario on the bottom.

So what we're doing this time is a little bit different. Next slide, please, is we're explicitly putting that in both of these scenarios in the reference the statewide planning forecast as well as the local reliability scenario. And Ethan Cooper will give you the details of those specific FSAP modeled pieces and how they overlay on or how they work with the AAEE and AAFS portions. And then, of course, the programmatic pieces, notably the fuel substitution scenarios, those are updated and they take into account the state implementation plan being in effect in some way, shape or form around 2030. So let's move to the next slide.

So a little bit more there. You're trying to drive it home that both of these forecast scenarios include FSAP modeling to account for the zero emission standards. The AAEE electricity and gas scenarios can be separated. Those are savings of electric end use or a gas end use. Then AAFS electricity and gas are joined. You can't separate that because you're taking away gas and adding hopefully a small amount of electricity in its place. So when we do the final statewide planning forecast and the local reliability forecast for these two load modifiers, we do prioritize fuel substitution over energy efficiency because the GHG impacts are approximately four times greater for electrification than for energy efficiency.

Next, and the way that we do that, and Ethan will go over this and show you some really nice graphs on how this affects the baseline forecast, is of course everything here with these load modifiers is incremental to a baseline forecast.

So we start with the baseline gas demand forecast and we remove gas displaced by the programmatic fuel substitution. So the piece of AAFS that I showed you today, so AAFS 3 programmatic or AAFS 4 programmatic, depending on if I'm looking at the statewide planning forecast or the local reliability scenario. Then Ethan applies the FSOT and using the scenarios that he has defined to account for zero emissions appliance standards which also include CARB SIP. Then finally for any gas that remains after that, we can apply the AAEE, which is all programmatic, which I also showed you today to any remaining gas consumption.

So the reason we have this hierarchy and we show it this way is because it's not possible to look at maybe the most aggressive, maybe not with the forecast, but if you were looking at some sort of policy work and if you're looking at AAFS 6 and AAFS or AAEE 6, there wouldn't be enough gas left to apply that amount of energy efficiency then.

And, in fact, we prefer the electrification to the energy efficiency on a GHG basis for these policy analyses. So that's why you'll see those definitions in Ethan's work as well.

So I think final slide here, just again foreshadowing that zero emissions appliance standards are modeled as part of AAFS 3-6, 3 and 4 being ones that go into the two forecast scenarios and I haven't talked about, right? That's something that's done separately. So then my last slide where I thank you very much and I think we'll all take questions at the end of course, unless someone has something pressing.

MS. RAITT: Great, thanks Ingrid. This is Heather.

Actually, I think there's one question that might be helpful just to address right now. I'm just going to jump in, Cynthia. Thanks. You'll we'll handle the questions later, but is there a link, this is from Alberto A., it says, is there a link to the 2023 hourly file supporting this data?

MS. NEUMANN: I haven't presented any hourly work.

(LAUGHTER)

MS. RAITT: Sorry.

MS. NEUMANN: But that will be included with the final manage forecast and when Quentin was talking about the peaks and all those kinds of things. And those will be made available, but they're not available yet.

MS. RAITT: Super, thank you. Thank you Ingrid for your presentation too.

MS. NEUMANN: Thank you.

MS. RAITT: So then we'll just move on to Nicholas Janusch and then from after him we'll hear Ethan Cooper. So thank you. Go ahead Nick.

MR. JANUSCH: Yeah, good afternoon. I'm Nicholas Janusch, and I'm the acting supervisor of the Efficiency Analysis Unit in the Advanced Electrification Analysis Branch in the Energy Assessments Division.

By, along with my colleague Ethan Cooper, we'll build off from Ingrid Neumann's presentation of the programmatic AAEE and AAFS results and we'll discuss the impacts from the inclusion of the zero emission appliance standards to the AAFS. I'll be setting the stage and characterizing the scenarios used for the zero emission appliance standards while Ethan Cooper will discuss the results. Next slide.

I should go back one, please. Sorry. But before we get into the details of modeling these zero emission appliance standards, I want to give a quick background to model these zero emission appliance standards. We use our Fuel Substitution Scenario Analysis Tool, also referred to FSSAT for short. It is a what if policy tool that we have used previously and it models the incremental impacts of fuel substitution at different levels of AAEE and AAFS assumptions. It was first used for the AB 3232 California Building Determination assessment, the 2022 Demand

Scenarios Project, and last year for the 2022 IEPR Demand Forecast Update where the first time we included the impacts from the zero emission appliance standards in the local reliability scenario. Next slide.

Let us give some context of why these zero emission appliance standards are incorporated in our additional achievable load modifiers. Back in 2021, the Energy Commission adopted the AB 3232 California Building Decarbonization Assessment Report, which assessed the potential for the state to reduce the emissions of greenhouse gases in the state's residential commercial building stock by at least 40 percent below 1990 levels by 2030.

One of the major takeaways from that assessment was that enormous technological transformation must occur, especially in existing buildings. For the state to reach its 2030 direct emission targets. Soon after the adoption of the California Building Decarbonization assessment, the Energy Commission recommended in the 2021 IEPR 6 million by 2030 heat pump goal. Soon after that, after Governor Newsom in a letter to the Air Resources Board in July '22, we stated the 6 million heat pump goal and also set a new goal of 3 million climate ready and climate friendly homes by 2030 and 7 million of those homes by 2035.

So the direction is for a huge amount of heat pumps. And last month at the building's electrification summit hosted by the California Energy Commission and the EPRI, the Electric Power Energy Institute, the top global building appliance manufacturers and distributors committed to help California achieve the 6 million heat pump goal. So targets, goals and commitments are all well and good, but they are not forecast scenarios. So what mechanism will actually get California across the finish line? That's where the zero and low NOx appliance standards that are occurring at the state and local level matter. These standards will be enforced at the point of sale. We're starting likely in 2027 in the Bay Area and 2030 for the state where any purchase appliance for space and water heating must adhere to the zero NOx appliance standard. And, to be clear, these regulators target ground level ozone pollution, particularly nitric oxide emissions or NOx emissions.

They do not target GHGs but GHG reduction or a code benefit of these regulations. Regardless, such regulations will reduce the amount of gas combustion appliances, so decrease gas demand, and increase the amount of electric appliances. So increase electric demand.

Finally, given the potentially impactful adoption of the 2022 state strategy for the state implementation plan by the California Air Resources Board the Energy

Commission, incorporate these zero emission appliance standards as part of the 2022 IEPR update and the local reliability scenario. These zero emission appliance standards has significant impacts to the forecast. So looking back in that forecast, the 2035 net peak megawatt impact from the standard for the 2022 local liability scenario was between 2,900 and 3,000 megawatts. Next slide, please.

So what are these various standards? Statewide, the Air Resources Board is looking at space and water heating standard in 2030. They could be looking at other end uses and may also include propane. The rulemaking process began earlier this year and the a vote by the Board is expected in 2025. At the local level, the Bay Area Air Quality Management District adopted their standard in March 2023, where in 2027 water heaters must adhere to the standard and 2029 space heaters go into effect. For the South Coast Air Quality Management District, they are are in the early stages of their process, but their potential standard will include both low emission and zero emission appliance standards that include multiple end uses beyond space and water heatings - heating. They will likely begin for the residential sector in 2029. Next slide, please.

However, these standards are all well and good, but they come with a lot of uncertainties. I have broken them down to two. So first up is the regulatory uncertainty, whether they happen and what form they take. So there are uncertainties about the regional regulatory differences. So in other words, what's going on at the local, state and federal level. Uncertainties about the timing of when the standards will go in effect. And, lastly, whether the scope of the regulations, so where the entire sector including mobile homes and propane will be part of it.

The second type of uncertainty is the - I describe as the adoption and compliance uncertainty. So how will people respond and will there be what I theme as strategic avoidance. There might be a better way of phrasing it, but strategic avoidance by people. For example, buying gas appliances right before the standard goes in effect, buying appliances out of state or the territory or any other behavior of trying to avoid switching to a zero emission appliance.

The other type is similar as the compliance rate on uncertainty. How many people will actually comply to the standard and how prevalent will be beyond when 2030, when things go effect and in the outer years. And then finally, the readiness of the standards uncertainty. Will manufacturers be ready, and as I mentioned before, they've committed to the 6 million heat pump goal. And will the grid infrastructure be ready for this regulation? What are the risks and consequences from the impacts for both the gas and electric systems if such rapid transformation occurs? So we want to minimize risks with electric system planning if the regulation is adopted as proposed. And on the flip side, if there is not such rapid adoption gas system managers need to minimize risks with gas reliability so that it is available. Thus, we recommend a conservative gas scenario with higher gas demand for gas system planning. But having stated these uncertainties, staff is confident that these zero emission appliance standards are reasonably expected to occur in some form and thus are included in our local reliability scenario and planning forecast. Next slide.

We still do not have a crystal ball in figuring out how everything will turn out, but as facts change and we learn how much progress is made, we will update our inputs and assumptions and how we characterize these standards. For example, the Bay Area Air Quality Management District have implementation working groups and will require interim reports two years prior to the compliance date for their zero NOx standards. The report should include information on technology development, market availability of zero NOx space heating appliances, potential costs of compliance, infrastructure readiness and availability of incentive programs to decrease these costs. Given that their first standard goes into effect for water heaters in 2027, we expect to get a glimpse and learn of the readiness when the report is submitted on January 1, 2025.

Further, as I mentioned before, the Air Resources Board is in the middle of their proceeding and expect to have a Board vote in 2025. Our CEC team will continue to track the Air Resources Board regulation and if you're prepared to rerun the model, if the Air Resources Board proposed regulation is different than our assumptions. Depending on the timing of such changes, we could adopt new results mid-year if needed. Next slide, please.

Now let's discuss the characterization of these zero emission appliance standards where I will first discuss the AAFS levers for each scenario as well as the assumed adoption rates. But, before I begin, I would like to state that these assumptions were developed in collaboration with the Air Resources Board. We are reviewing these assumptions with stakeholders including CPUC, CAISO, and the Air Resources Board. As can be seen in the table, four of the six scenarios contain zero emission appliance standards. AAFS 3 through AAFS 6. Each scenario has different levels of programmatic AAEE and AAFS as Ingrid Neumann presented. AAEE 3, for the first column, what we're theming as AAFS 3 is there, but AAEE 2 in the remaining three scenarios. Why since energy efficiency and fuel substitutions are rival or competitive and AAEE 2 allows for more fuel substitutes to occur. So going from left to right, having AAEE 2, it allows for more fuel substitution, as you get more aggressive with the scenarios.

The amount of programmatic AAFS increases in aggressiveness. Now how our FSSAT modeling works is it takes the baseline gas forecast and gives haircuts by each AAEE and AAFS scenario. So the more programmatic AAFS occurs, the less residual gas is available and eligible to be fuel substituted and thus be impacted by the zero emission appliance standard. So keep in mind that when we model these appliance standards scenarios, they're incremental to the existing programmatic and incentive activities. Next slide.

Now characterizing the zero emission appliance technology standard that goes into FSSAT all include space and water heating while a AAFS 5 and AAFS 6 include other end uses like cooking and clothes drying as well as residential propane. At the local level all have the same penetration for the Bay Area Air Quality Management District. But for AAFS 6 it includes residential end uses for the South Coast Air Quality Management District starting in 2029. Next slide.

The other levers are the technology and adoption rates. All scenarios have the same set of technologies being modeled. However, the adoption of these technologies are evenly mixed where each potential electric technology has an equal chance of being added. However, for AAFS 6, the efficiency mix is highly weighted where more of the higher efficient technologies or heat pump will be adopted. As seen and read, we modified our AAFS 6 assumptions since the August workshop from a scenario where it was strictly the most efficient equipment in the sets that could be adopted. We revised this even though it would be an interesting to see this technical potential and impacts, but a highly weighted mix is a more realistic and more germane for this forecast.

Finally, the adoption rate assumes a linear adoption rate of 2030, which I'll detail in the upcoming slides. There is a lot of uncertainty with these rates and keeping them linear has been the most agreeable path. Notice that it is the planning forecast where we do a slight downward adjustment in the adoption of the heat pumps in the interim years before the standard goes into effect. Next slide.

So here's basically the summary slide without some red ink on it. Summarizing our assumptions. Next slide, please. But to clarify the focus for today and what Ethan will present our focus is mostly on the first two columns, AAFS 3 and AAFS 4, which are included in the planning forecast and local reliability scenario. Next slide.

As for the adoption and compliance rates, everything in white are adoption rates that do not vary across scenarios. They include what is happening in new construction across the state and what's happening with replaced on burnout in the Bay Area Air Quality Management District where for new construction is 100 percent for commercial sector starting in 2029 and a hundred percent for residential sector starting in 2026. The Bay Area has water heaters as being a hundred percent replaced starting in 2027 and space heaters is being replaced in 2029. Next slide.

Now the green area shows the variation of adoption rates across the scenarios and the blue shows what is assumed for residential propane. The replace on burnout is 100 percent starting in 2030 to adhere to the Air Resources Board standard. While there is a 10 percent reductions ramp up rate for AAFS 3 or the planning scenario. And as can be seen residential propane falls similar adoption rates as for gas. And to restate again these assumptions were developed in collaboration with the

Air Resources Board. We are reviewing these assumptions with stakeholders including CPUC, CAISO and the California Air Resource Board. The direction from our leadership is to move forward with what we are presenting today. Next slide, please.

Now before I turn it over to Ethan Cooper to discuss the results of these scenarios, I want to summarize a few changes since the 2022 IEPR update. The first is the most major one and Ingrid touched on it, both the planning forecast and local reliability scenarios include the zero emission standards. So both not just one. Instead of just one scenario. We have four and they vary by technology weighting. Note that last year we assumed highly weighted efficiency in that scenario. So this year our scenarios are more conservative and includes more electric resistant technology penetration. We updated some of our adoption assumptions based on new information from the local air districts and now we include residential propane and other end uses in our scenarios. Lastly, we have updated FSSAT with the latest data available from the 2023 IEPR forecast as well as we have updated FSSAT's assumptions on regional air conditioner penetration rates in PG&E territory. And that data was generated from analysis by Recurve using AMI data. Next slide.

So thank you so much for your attention. Let me pass it on to our next speaker, Ethan Cooper who is the technical staff in our units and he will discuss the results

And you have to probably advance a few slides. I have some appendix slides that give some details about the zero emission appliance standards.

MR. COOPER: All right there. Thank you, Nick.

I'm Ethan Cooper and right now I'm going to be going moving into looking at our results for the incorporation of the zero risk compliance standards into our AAFS scenarios 3 through 6, they're being adopted for the 2023 IEPR forecast. Next slide, please.

So for the results here, we're going to kind of split it up into two main sections. The first section is going to be looking at our overall energy impacts for all of the AAFS scenarios that are going to be modeling the zero emission appliance standard into that includes scenarios 3 through 6 that could split it up and looking at both the gas electricity impacts for each of these AAFS scenarios. We'll taking a look at a bit of an impact comparison for these scenarios to kind of see for each AAFS scenario, what are the energy impacts are making some change to our characterization of ZE standard while keeping all else equal. Just basically seeing what are really the major impacts of our technology characterization choices that we have in terms of how it affects our gas electric impacts for the ZE standard. And then beyond that we're going to go into a second section which is going to be looking at really just taking a more deeper dive into the AAEE and AAFS load modifiers that Nick mentioned are going to be being used for the demand forecast scenarios.

So both for the planning forecast and local liability scenario. This will include looking at both the gas and electricity impacts for AAEE and AAFS load modifiers for our demand forecast scenarios. And then looking at a comparison of these zero emission appliance standards, just the impact of the zero appliance standard for the local liability scenario and the results we have for the 2022 IEPR update. And then the results we are seeing for this 2023 IEPR cycle this year. And then lastly, looking at a bit of view about the added electric appliances that are coming into, they're going to be installed into buildings because of our different AAFS scenarios 3 and 4 for the two demand forecast scenarios. With that, can you move to the next slide, please?

Alright, so I want to just pinpoint again our major technology characterization assumptions that we have for the 0 percent appliance standard in each of our AAFS scenarios because it's going to be important to understand why the gas impacts for each scenario are going to be changing between scenarios 3 and 6. And it's also important because when we're doing our impact comparisons, the changes we're going to be making are to any of the FSSAT characterization levers we have in the light green boxes. So like the water heating and space heating choice or the AQMD choice. So just wanted to go get that out there before we start going all in on the results. So with that we move on to the next slide.

Alright, so now we're going to be going over our overall impacts for gas savings, electricity additions for the AAFS scenarios 3 through 6. Next slide, please.

So starting with AAFS scenarios three and four, we see that scenario 3 and 4 have a fairly large difference between the two of them and that difference is being predominantly driven by the programmatic impacts that we see for both AAFS scenario 3 and 4. See there's about 640 MM therms more gas savings in scenario 4 starting in 2030.

But by 2040 that does go down to about 84 MM therms. And the reason why it goes down starting I think in 2036 is because of the fact that our zero emission appliance standard gas savings for AAFS scenario 3 started to become greater than what we see for AAFS scenario 4 in that year, elbow to 2040. And we're going to go into more as to why that is happening. We're going to take the deeper dive into AAFS scenarios 3 and 4 that are being used to the demand forecast scenarios. Can you move to the next slide, please?

Then taking a look at our AAFS scenarios 5 and 6, we can see that the difference between these two scenarios is much lower than we saw for scenarios four, sorry, three and four. And the main reason for that is really the only main difference between scenarios 5 and 6 is the programmatic contributions and they aren't too different in these two scenarios.

So really the zero return appliance standards, gas savings or electricity addition impacts aren't too different between scenarios 5 and 6 or 3 and 4. However, that impact does come into play when we go between scenarios four and five as we could show on the next slide. But overall, the difference between scenarios 5 and 6 are that scenario 6 saves about 135 MM therms is more gas in 2030 and about 19 MM therms is more in 2040. Move on to the next slide. Thank you.

Yeah, so this is where we're showing the largest impact between the AAFS scenarios when we bring in the zero emission supply standard modeling comes between scenarios 4 and 5, and that is just due to the fact that scenarios 5 and 6, as we showed in our characterization table earlier on in this presentation, are including fuel substitution for not just water and space heaters for the gas for - gas appliances, but also for fuel substitution of propane, residential propane, gas and water heaters along with fuel substitution for the cooking and close rank end uses.

So really AAFS scenarios 5 and 6 provide us with a lot more areas for the zero supply standard to have any gas savings for fuel substitution to occur leading to this large difference between the orange line, which is AAFS 5 and the green line, which is AAFS 4. But that can move on to the next slide to now look at electricity impacts.

Here's where we kind of start seeing an interesting situation where AAFS scenario 3 is kind of going against what we'd expect it to be doing where instead of being greater than AAFS scenario 4 throughout the entire forecast is actually, sorry lower than AAFS scenario 4 throughout the entire forecast. It is actually higher than scenario 4 starting in 2037. And we can see that the difference between AAFS scenario 4 and 3 is about 2,300 gigawatt hours in 2030 with scenario 4 being greater than, but in 2040 it's about 3,100 gigawatt greater, sorry difference in 2040 with now AAFS scenario three being greater.

We're going to go into why that is different in the next few slides. But before that I wanted to go onto the next slide to show the impacts we have for scenario 5 and 6 before we compare all of them together. So you can see that for AAFS scenario 5, we are again seeing the situation where scenario 5 is much greater, not much greater, but it is greater than scenario 6 throughout 2030 and beyond. And that is because of the zero emission appliance standard and how we're modeling it differently between scenarios 5 and 6. So AAFS scenario 5 saves about 450 gigawatt hours or more electricity in 2030 and about 3,570 gigawatt hours more in 2040. So if we move on to the next slide, I'll kind of explain the difference between the two, between why scenarios 3 and 4 look different and same for scenario 5 and 6.

So for the reason why AAFS scenario 5 is greater than scenario 6 for electricity impact is because of the fact that for AAFS scenario 6, we're modeling the zero-emission appliance standard using a technology efficiency weighting choice of high rather than even, which basically allows us to be installing more of the higher efficient appliances into buildings rather than the lower efficient appliances when we're using the, even waiting for AAFS scenario 5 leading to an overall reduction in the electric impact for that scenario. And then for scenarios 3 and 4, the reason why scenario 3 is greater than scenario 4 starting in 2038 again is because, not because of how we're modeling the standard, but it's just because of the fact that the ZE standard has more gas savings for AAFS scenario

3 starting in 2036, which leads to starting at 2037, the ZE standard at a electricity AAFS scenario 3 also started to become greater than scenario 4 and that goes all the way up to 2040.

Now we're going to go more into depth about really why it is so much greater where the gas savings were still AAFS scenario 3 and 4 started getting closer and closer together, but they did not show AAFS 4 being lower gas savings is scenario three. We'll go into that later on when we show the impact comparison of scenarios 3 and 4 alongside the impacts of AAEE as well. So with that, I'll move on to the next slide.

So before we go on to looking into the further deep analysis on scenarios 3 and 4, I kind of want to go over our scenario comparison that I discussed earlier. So for this we're just really looking at what are the major energy implications of some of our major ZE appliance technology characterization levers that we had in the table shown in the beginning of the presentation before we got into the results section.

And for that really we're just showing each of our AAFS scenarios in their original form, which is basically all of our solid colored lines on this slide and the following slides and then comparing them to another version of that scenario where we've changed one or one or multiple of our assumptions we have and our technology characterization levers, those light green, those light green rows that I talked about earlier. And basically just seeing what is the energy impact of making that change while making sure we keep everything else for that scenario equal. So just changing as different assumptions to our ZE standard technology characterization levers. So for AAFS scenario 3 and 4, the two choices we made is that first scenario 3 we wanted to see what is our energy impact of actually putting in that 10 percent put a line wrap up adoption rate. Basically we did that by comparing our original AAFS scenario three with a version of AAFS scenario 3 called AAFS 3, no low ramp, which is our dashed or red line that looks at our AAFS scenario 3.

But using the normal linear rep adoption rate that is used for AAFS scenarios 4 through 6, basically the one that does not have any reduction to the interim years. And for that one we can see that as we expected the gas savings that you get for AAFS scenario 3 using that 10 percent reduction to our linear ramp up adoption rate lowers the amount of gas savings that we would see by about 95 MM therms and 2033 to have used the normal linear ramp of adoption rate that is being used in all of our other AAFS scenarios. And then for scenario 4, we're basically looking at what are the impacts of including the Bay Area

AQMD's emission rules into our modeling of these supply standards. And that is shown by AAFS scenario 4, no Bay Area AQMD or dash green line that is showing the impacts of running the same scenario but having the Bay Area mission rules excluded from our modeling run.

And we can see here that the impacts including AAFS scenario 4, the impacts for AAFS scenario 4 including the Bay Area AQMD's emission rules provide us with about 35 MM therms more gas savings at 2030 than if we were to run that same scenario but without the impacts of the zero emission about, sorry, without the impacts of the Bay Are's emission rules. So kind of a key takeaway of this slide, what we can see on the next slide is that there is a pretty noticeable difference in the different choices we made for these scenario comparisons, but they aren't quite that large as we were additionally expecting them to be for the next slide.

This slide is just the electricity impact showing the same scenario but just reverse energy looking at different energy, looking at gigawatt hours added rather than MM therm saved. And so we can kind of see that AAFS scenario three including that linear, that reduction toward linear rep of adoption rate reduces the amount of electricity that gets added for that scenario by about 1040 gigawatt hours in 2030. If we to have run that scenario with the normal linear ramp up adoption rate being used for the other AAFS scenarios.

And then for AAFS scenario 4, we can see that including the zero emission appliance standard, sorry the emission rules for the Bay Area AQMD increases the amount of electricity being added for that scenario by about 426 equal hours. In 2030 that if we were to have run that scenario without the impact to the Bay Area emission rules.

Moving on to the next slide we now wanted to go see for AAFS scenario 5, how big of an impact is our choice for including the zero emission appliance standard to be modeled for other FSSAT end uses? Basically cooking clothes drying as well as for residential propane fuel substitution of water and space heating appliances. And that difference was shown by creating the AAFS scenario 5 only water and space heating scenario. The dashed orange line that basically just shows us that including the zero emission appliance standard modeling for residential propane fuel substitution as well as for the other FSSAT end uses adds a considerable amount more natural gas savings.

About 670 MM therms in 2040 that approved to have just run AAFS scenario 5 with only allowing for fuel substitution from the ZE standard into the water and space heating appliances. And then for AAFS scenario 6, we wanted to see what was the impact really for our gas savings on including the South Coast AQMD's emission measures. But we can see here by 2030 having the zero emission appliance, the emission measures for the South Coast AQMD adds about 55 MM therms if there's more gas savings for our scenario in 2030 than if we were to have run the scenario without including the impact of the zero emission, the impacts of the South Coast AQMD's emission measures, which is in our dashed blue line. So with that, if we move to the next slide.

I want to then show the electricity impacts for AAFS scenario 5 and 6 for our scenario comparisons. So for AAFS scenario 5, we can see that the inclusion of modeling the zero supply standard for other Fuel Substitution Scenario Analysis Tool (FFSAT) end uses and residential propane fuel and the residential propane fuels really increases the amount of electricity that gets added for scenario 5 by about 10,700 gigawatt hours in 2040. And if we were to have run that scenario without the inclusion of fuel substitution for those other asset end uses or for residential propane fuels and then for AAFS scenario 6, we see that running the scenario with the impacts of the South Coast AQMD's mission rules adds about 535 gigawatt hours in 2030. Then if we were to have run that scenario without having the impacts of the South Coast AQMD mission rules be included. So really it's a noticeable difference for AAFS scenario 6 between running it with and without the South Coast AQMD, but it's not that large.

It's not as large at least as what we see for running AAFS scenario 5 with or without fuel substitution for the other FSSAT end uses or for residential propane fuel substitution. And then the last one that we wanted to add here was trying to go see what is the impact of running our AAFS scenario 6, both with using the technology efficiency weighting that we have for that scenario right now, which is the high choice. It's basically allowing for more high efficient appliances to be installed rather than the lower efficient alternatives compared to running the AAFS scenario, the dotted line using the evenly weighted efficiency choice that is being used for all the other AAFS scenarios. And we can see here that running AAFS scenario six with our high efficiency waiting gives us about 3,500 gigawatt hours of more less electricity being added to the grid in 2040 than compared to if we were to have run AAFS scenario 6 using the even instead of the high efficiency waiting choice.

With that, if we move to the next slide, that's the end of our overall impacts for all the AAFS scenarios. We're now going to move into a more detailed impact of the AAFS scenarios 3 and 4 that are being used with the planning forecast and low core liability scenario. Next slide, please.

So here we're going to be showing the gas impacts that our AAEE and AAFS load modifiers have to the plan forecast and again for, I think I forgot to mention this earlier, but we're only going to be looking at for this and the following slides, the residential and the commercial sectors since those are the only two sectors that the zero emission appliance standard is having any gas fuel substitution being modeled for. And before we get into this, I again want to go explain the process that FSSAT works when it tries to do any fuel substitution calculations for any FSSAT based fuel substitution.

As Ingrid mentioned earlier, at the end of her slides is that we have our baseline gas forecast residential and commercial sector, which is any gas available for any fuel substitution or energy efficiency measures. That forecast then gets reduced by any of the impacts we have from programmatic AAFS to give us a modified baseline forecast that is any gas left over for any FSSAT based or in this case ZE standard based fuel substitution. Once that fuel substitution is done, we then reduce the baseline forecast one more time - that modified forecast gets reduced to now incorporate the impacts of programmatic and FSSAT based fuel substitution to leave us with a revised forecast that gives us any gas left over for any energy efficiency from AAEE to occur for the gas - for any gas energy efficiency to occur for AAEE scenarios. And that's where we can see in some cases we may have a chance where once we only have gas leftover for AAEE after fuel substitution has been accounted for, we might not have enough gas actually available for all the AAEE savings to be achieved and that's what we would show in this slide, any AAEE savings only showing the savings that are able to be achieved after we incorporate the impacts of programmatic AAFS and ZE standard AAFS into the baseline forecast.

So with that I'm going to move on to the next slide to go show on our baseline forecast, which is our solid black lineup there, what is the impact for programmatic AAFS scenario 3 in the planning forecast. We see that it reduces our baseline forecast by about 3.8 percent in 2040, which we then could compare that to the next slide.

Our ZE standards impact, which is shown here considerably greater in terms of the baseline gas reduction. It reduces the baseline gas forecast further by about 64.1 percent in 2040 and overall has a gas savings amount of about 3951 MM therms in 2040. So clearly we see that the ZE standard portion of AAFS is doing a lot of the gas savings work of the entire AAFS scenario 3. Move on to the next slide -

to then add in the impacts of AAE scenario 2. We can see that it reduces the forecast one step further by reducing our gas baseline forecast by about 4.4 percent in 2040 to lead to all the different wedges, the programmatic, ZE standard and AAEE portions of our load modifiers reducing the baseline forecast by about 72.3 percent in 2040. And this leads to an overall reduction in the gas savings for all three wedges in 2040 of about 4,450 MM therms. And move on to the next slide.

I want to quickly before going into local liability scenario kind of show the progression in the baseline gas reduction we have for our different load modifiers from 2030 to 2040. And I kind just want to point out the fact that for the ZE standard we have, even in 2030, a considerable amount of gas savings happening from the ZE standard, it's about 14 percent in 2030. That's how much it reduces the baseline gas forecast and they want to show the substantial jump we have from 2030 to 2040 the ZE standard, which just shows how much gas savings happen from 2030 onwards because of us now having the zero appliance standard becoming to full effect and add its a 100 percent compliance rate. Move on to the next slide and then one more.

Now I'm going to show the impact of the local liability scenario, the local scenarios AAEE and AAFS load modifiers on our commercial and residential baseline gas forecast. We can see that for AAFS scenario 4, we have a considerable amount more baseline gas reduction for AAFS scenario 4, the programmatic contribution, it's now about 9.4 percent reduction to the baseline forecast in 2040. If we move on to the next slide.

We can see that the zero risk appliance standard is still out of extra zero - extra natural gas savings for the fuel substitution from the ZE standard. See that it reduces the baseline forecast further by about 59.5 percent in 2040 leading to an overall savings of about 3666 therms in 2040. But the one thing we do want to note here is that the baseline gas reduction and the gas savings value actually has gone down for the ZE standard from what we saw in the planning forecast. And that is actually important to know because it is shown here to be kind of made up actually by the extra gas savings we have for the programmatic portion of AAFS. This time for the low city scenario than we had in the planning forecast. And move on to the next slide.

I want to show the final impact we have of our programmatic AAEE scenario 2. We reduces the baseline forecast one step further to about reducing it by 3.8 percent in 2040 leading to the total combination of all those wedges, reducing our baseline forecast by about 72.7 percent in 2040 leading to an overall gas savings amount of about 4,476 MM therms in 2040. I kind of wanted to also show these baseline gas reduction percentages to just show how big of an impact are AAEE and AAFS load modifiers combined have on reducing our baseline gas consumption for both the residential and commercial sector rather than just showing the overall gas impacts that each scenario has alone rather than showing its comparison to the baseline forecast. If we move one more scenario sorry, one more slide.

I want to go show that again. There's a substantial jump in the ZE standard gas savings and or I guess a significant jump in the baseline gas reduction percentage we have for the AAFS ZE standard in 2030 compared to what we have in 2040. 2030 baseline gas reduction for the AAFS ZE standard is a bit higher than we saw in the planning forecast, but again for 2040 we see that the baseline gas reduction percentage as well as the gas savings are lower in 2040 than what we saw for the zero emission appliance standard. So with that move on to the next slide.

So now I want to kind of go show in the table what are the actual differences between the local liability scenario and the planning forecasts gas impacts to the demand forecast scenarios between 2030 and 2040. The important thing to note in this table is that we can see that the load modifier total in 2030 has a very large difference between the two gas savings amounts, where the local liability scenario is saving about 600 MM therms more gas in 2030 than the planning forecast is. However, I want to note that that does change in the 2040 values where now the local liability scenario is still saving more gas but the difference between the two are considerably lower but only about 20 MM therms difference. And I want to go pinpoint that the predominant reason is why that is happening is because of our AAFS ZE standard. Now having, as we've mentioned in the slides way earlier, that the planning forecast ZE standard gas savings in 2040 are going to be higher than we see for the local liability scenario in 2040 by about I think 300 MM therm more gas savings for the planning forecast ZE standard savings than what we see for the local liability scenario. Move on to the next slide.

I'm going to highlight that the main reason for that is because of our programmatic AAFS contributions introducing our baseline gas forecast and the local liability scenario versus the planning forecast. And the fact is that the ZE standard really has no difference in our technology characterization of that standard from 2030 onwards. It's only different in the pre-2030 timeline because we have that production in the interim years of adoption for the planning forecast then what we do in the local ability scenario. But beyond that, they have the same compliance rates for electric appliances that are going to be replaced each year with - sorry, gas appliances being replaced each with an electric alternative. That leads to the fact that if we have a higher AAFS programmatic scenario, we're going to thereby have a lower amount of baseline gas available for the ZE standard to replace, which is what we're seeing here.

We have a higher local liability scenario AAFS forecast, which means we have lower gas available for the ZE standard to do any fuel substitution on, which is why when compare to the baseline gas available for any fuel substitution from the ZE standard for the planning forecast, which leads to the gas savings for the planning forecast for the ZE standard to be greater than the local liability scenario.

If we move on to the next slide then I'm going to go into the electricity impacts now for these two scenarios. So for AAFS scenario 3, the ZE standard appears to have quite a large impact in terms of electricity being added to the grid. Even starting in 2030 when the first year of full compliance happens for the CE standard and that's also because the programmatic - the AAFS 3 programmatic electricity additions are quite small. We compare to the ZE standard and to the AAEE electricity that's being saved by scenario 3. And by 2040 we see that the overall impact of the ZE standard electricity additions are about 41,800 gigawatt hours, which we compare to AAFS programmatic is about 25 times greater amounts of electricity additions than what we see for the programmatic portions.

And the reason for that is because of the fact that for the programmatic AAFS that's looking at efficient electrification, really trying to go incentivize, putting in the most efficient appliances out there to replace gas equipment. Whereas for the ZE standard and for the FSSAT modeling, we're basically allowing for not a majority but a larger amount of different appliances to replace gas equipment for every end. Use each of those appliances having different levels of efficiency that dictate how much electric gets added for gas or moved for each technology. And just having that variety of electric technologies out there means that we have more likelihood of putting in less efficient appliances that would be increasing our amount of electricity being added than what we are seeing for the programmatic portions. And overall our net impact for all of our AAFS and AAEE load modifiers in 2040 results in about a 31,677 gigawatt hour increase in electricity for the forecast in the planning forecast by 2040.

And that's important to note because of the - go to the next slide.

We're going to compare that to the total we have connect back total we have to all the AAFS and AEE load modifiers in 2040 being only about 31,816 gigawatt of electricity, which is still higher than the planning forecast but not by much. And the main reasons for that as we're going to show in the next slide. But before that I'm going to stay here and just show that zero and appliance standards savings in 2040 do go down to about only 37,716 gigawatt hours, which now compared to the programmatic AAFS scenario is only about 13 times higher. And the programmatic AAFS does go up by a little bit, as we can see by the blue bars having I guess just being easier to see in this graph than what we saw in the planning forecast.

And we also have lower AAEE gas savings which makes sense because using a lower AAEE - sorry scenario. So if you go to the next slide.

I'm going to go kind of show impacts of the - electric impact for our demand forecast scenarios side by side for the planning forecast and local liability in both 2030 and 2040 to show really explaining why we saw AAFS scenario 3 electricity impacts being greater than AAFS scenario 4 starting in I believe it was 2038. That's because as we can see here for the load modifier total, the last row in our light green boxes, we see that at 2030 the local liability scenario is adding about 7,365 gigawatt of electricity where the planning forecast is only adding about 2363. So there's quite a big difference between local liability and planning forecast with local liability being higher. But once we move on to 2040, as I kind of pinpointed in the graphs and slide before this, we only have a small difference between the local ability scenario and planning forecasts at electricity kind of falling what we have on our light blue row below that showing that there was only a 20 MM therms difference between the gas savings and the local reliability and planning forecast.

Now we only have about a little bit less than 200 gigawatt hour difference between the local ability scenario and the planning forecast in 2040 for AAEE and AAFS load modifiers. And the main contributing factor to those numbers not being too different is, again, because the ZE standard has a lot more electricity addition to the planning forecast than it does in the local ability scenario, which is just a bit of a byproduct of the fact that we have more ZE standard gas savings in the planning forecast than the local liability scenario. And that makes it so that way the difference between the programmatic gigawatt hour electricity additions in the planning forecast versus local liability scenario not being great enough to make up for the difference we see for the ZE standard being greater in the planning forecast than in the local reliability scenario. Leading to the situation we saw in the charts - I think the second chart that I showed or the first chart I showed for the comparing AAFS 3 and 4 is electricity impact having scenario three be greater, the scenario four starting in 2038 and staying the same all the to 2040.

With that I'm going to move on to the next slide.

To kind of end off on our energy impact assumptions or analysis by showing what our local reliability ZE standard gas impacts were in the 2022 IEPR update versus what we are seeing for them in our 2023 IEPR cycle. This year we noticed that the gas standard savings for the locality scenario are going to be lower for this IEPR cycle than they were last year. And the primary reason for that is the fact that we are using a residential baseline gas forecast for the 2023 IEPR that is lower than what we are using for the 2021 IEPR that was used when we ran the ZE standard for the 2021 -sorry, in the 2022 IEPR update. This leads to just the fact that the ZE standard is going to have less gas available for any fuel substitution than what we saw last year. If move on to the next slide.

I want to show the electricity impact, which is actually the reverse what we're seeing for the gas savings impact. We're now using the - we're now the ZE standard is actually showing high electricity additions starting in 2030 for the 2023 IEPR when compared to the 2022 IEPR update. And that is being driven largely by the fact that our efficiency weighting choice has been changed. What we were using last year to this year, where last year we were using a high efficiency weighting choice that basically gave more priority for the higher efficient appliances to go be installed to replace gas equipment where now we're using an evenly weighted efficiency choice that gives more - or not more priority but basically gives equal priority to all appliances to replace gas's equipment basically allowing or - basically having us put in more or less efficient appliances than what we saw last year. With that, I'll move on to the next slide, which is kind of the final slides that I have for this presentation.

And this is just basically looking at our electric appliance equipment that's being installed from our programmatic and ZE standard portions of AAFS throughout the planning forecast on this slide and for the local reliability scenario on the following slide. So here we can go see this chart showing our residential air and water heat pumps and electric resistance technology that are being installed for each AAFS scenario with blue showing our heat pumps and then orange showing our electric resistance. But electric resistance only being for our water heating end use as the HVAC end use is only looking at heat pump technologies. And one last thing note here is that this chart is again only looking at the residential sector and not looking at any commercial heat pumps since we're not currently able to in our FSSAT tool model the impact or model the amount of heat pumps being installed for the commercial sector. And it also does not incorporate any of the heat pumps that have been previously installed in years prior to 2024.

So we also have a line at the very top which is called 6 million residential heat pumps, which is kind showing our target similar to the one that we have. Similar to the one that was established in the 2021 IEPR that Nick mentioned about having 6 million heat pumps be installed by 2030, but we're only limiting it to residential heat pumps for our chart because that's the only sector we're showing the AAFS stock for. We can see here that in 2030 for the planning forecast we are adding about, I would say I think there's about 3.3 million heat pumps being installed by 2030 from our AAFS scenario 3. And then there's an extra 1.1 million electric resistance appliances being installed in that same year, for total about 4.4 electric appliances total in 2030 being installed. We can see here that if we're looking at just our projected installations of key pump appliances from the AAFS scenario 4 from 2024 to 2030, in 2030, we do not appear right now to be in the path towards reaching that 6 million residential heat pump target.

And if we were to also add in, as you see on the text box to the left, the roughly 1.15 million residential and commercial heat pumps that we estimate to have currently been installed in California, which is based off of CEC analysis, we still only about shy of 5 million heat pumps. So still does not appear that we are on the path to the planning forecast to be reaching - do not appear to be on the path to - but are slowly approaching that 6 million heat pump goal. However, we also have to note that because we're not able to include commercial appliances, that is also affecting the amount of forecasted AAFS stock values we're going to be including. So that path could very well change to be reaching that 6 million heat pump target were we able to include the commercial sector installed heat pumps from our AAFS scenarios. Move on to the next slide.

I want to show the impacts of the local liability scenario. We're now in 2030 for AAFS scenario four, we're actually already just from the impacts of AAFS scenario 4 installing almost 5 million heat pumps by 2030 now about an extra 1.112 million electric resistance appliances by 2030 as well leading to an overall total amount of about a little more than 6 million total electric appliances being installed by that year for AAFS scenario 4. But we're looking at just the heat pumps of 2030 and including our impacts that we have for the roughly 1.5 million residential and commercial heat pumps already installed in the state, we can see that we are actually getting to above 6 million heat pumps being installed by 2030, which kind of shows that local reliability scenario does appear to be on the path towards reaching that 6 million heat pump target.

And I guess the final conclusion for these last two slides are just showing that for the local reliability scenario we're quite confident or we are confident that that scenario does appear to be on the correct path towards reaching the installation of 6 million heat pumps by 2030, but we're not as confident for the planning forecast that it'll be able to is on the path yet right now to be reaching that 2030 6 million heat pump goal.

But we also need to remember that without having the impacts of commercial heat pumps for our AAFS results, that path is not exactly the true one. That could change once we are able to incorporate the impact of added heat pumps for the commercial sector with our FSSAT tool. So with that move on to the next slide, which I think is just the final slide. So I'll say thank you all to everyone and I think we're moving on to questions. So I'm going to pass on to Cynthia.

MS. RAITT: Thank you, Ethan. This is Heather. Ethan and Nick, and first we'll just ask Vice Chair Gunda if he had any questions for you.

VICE CHAIR GUNDA: Thank you, Heather. First I want to just say thank you Ingrid, Nick and Ethan. That's so much content there. I was just going through slide by slide over again. I know we had a lot of internal discussions and briefings, but just a large amount of content to digest. I have a couple of questions but I would like to - I don't see any Q and A in the public, so I'll try to set up a couple of questions and let's circle back.

So I think at the 30,000 foot level, I just want to go back to maybe start with Ingrid, if Ingrid's still here.

MS. NEUMANN: I'm here.

VICE CHAIR GUNDA: Okay, so Ingrid just can you just for the record, confirm that the pyramid of scenarios that you showed. AAEE and AAFS the 1 and 2, so that applies, but for AAEE and AAFS, and just making sure that you also explain that the 1 and 2 are primarily coming from the potential end goal study or anything else you want to add. I just want to make sure for the record we have that, how are we constructing the first two scenarios?

MS. NEUMANN: Yeah, so the scenarios, just like in previous years, the 1 was the most conservative, right? So 1 and 2 are, well, okay, 1 we're not using for the forecast. Two we are using for the AAEE 2 for the local reliability but not for any fuel sub. Then 3 is our reference that we're using both for AAEE and AAFS for the statewide planning scenario. Four we're using AAFS 4 in conjunction with a AAEE 2 for the local planning. Then the most aggressive or optimistic AAEE and AAFS 5 and 6, the boulder blue and the violet are not being used for any forecast scenarios.

VICE CHAIR GUNDA: Yeah, so just making sure though on just the inputs that go into those 1 and 2. Could you just expand on that for the record? Yeah.

MS. NEUMANN: Oh. Yeah, so that's true. So predominantly what does go in there is a conservative scenario from the potential goal study for IOU programs. Our own conservative estimate of the POU programs, they only submit one scenario for us, and then we used - based on the differences in the CPUC'S potential goal study between their more conservative scenarios and their more aggressive scenarios by sector. We used those if they were 9 percent lower or 5 percent higher or whatever it was, we used that to inform the sector based conservative view and aggressive view of a POU program scenario. And we did that in 2021. We did that again in 2023.

So those are two big data streams there. And then pretty much the Title 24, 2022 building standards, those are there in a conservative view as far as how much implementation compliance and that sort of thing. But those are the core pieces that do go in to those more conservative scenarios.

VICE CHAIR GUNDA: Yes. Okay, thank you. So I just wanted to get that on the record because we don't discuss that today as much, but we know we discussed that in the assumptions workshops.

So in terms of the magnitude of efficiency and AAFS, do we have - so we mostly talk about that in energy and terms. So we're talking about gigawatt hours and terms, could you just give an indication of what the magnitude in terms of megawatts generally - go ahead.

MS. NEUMANN: Well, I mean, so those would be the hourly values, right? I mean or some peak ones. And so we haven't put those together yet,

VICE CHAIR GUNDA: But from previous years, what is typically the magnitude of the building? The - like the fuel substitution like for example last year on the outlet side.

MS. NEUMANN: Well, I mean it was a lot more than it would be now. Yeah, I know. I don't have it right now. Sorry.

VICE CHAIR GUNDA: Sorry, sorry. I should not have put you on the spot like that. I think where I'm going with the question is just what do you expect in terms of the megawatts change in the fuel substitution is where I'm going. Like when we talk about reasonableness to how do we want to plan for it, what levels of megawatt impacts are we generally thinking about in directionally?

MS. NEUMANN: So I mean for the programmatic pieces that's smaller, right? For the totals, I don't think the totals changed as much with the SIP implementation accounted for. Those would look very similar to what we saw in 2022 for the local reliability scenario.

MR. COOPER: I think I can speak to that one. I think that's -

MS. NEUMANN: I was hoping that you might have that number.

MR. COOPER: I think Nick mentioned - I think during his presentation that it was about 3000 ish megawatt increase from the zero emission plan standard in the local liability scenario in 2035. And that I think was the megawatt difference between planning forecast and local liability scenario. But most of that difference was from the inclusion of the zero emission appliance standard in the local reliability scenario. So it was quite a big jump up, particularly because we were including the zero emission appliance standard in the local scenario while we weren't in the planning forecast. So it might be similar for both the planning forecast and local reliability scenario this year in terms of the zero appliance standards impact.

VICE CHAIR GUNDA: Got it.

So Ethan, I think this is more a comment. Just first of all, just in the same spirit of this morning, the amount of work that's going into this is just tremendous. I mean I kind see the evolution of our building work. I remember when Nick joined the team and Ingrid joined the team and where we were to where are today in terms of continuing to change the rigor and how we think about all these policy issues is just really fabulous to watch. So I'm just now I'm thinking through next year we're going to puts hundred report and a significant part of our SB 100 work is going to be the demand scenarios and there is this blurring of demand forecast, demand scenarios. And what are those handoff points? I'm just trying to figure out when we talk about the penetration, the total addressable market in a highly electrified future is probably more or less the same.

It's like a part of the question is every time we change the assumptions, the s-curve or the penetration changes. And so where do you build those megawatts that are required to keep the system reliable, continue to change? And I'm trying to just figure out how do we support the discussion of overall in 2045 timeframe, whether it's the 2021 SB 100 report in the future report. We're thinking about a high electrification future.

So directionally we're going to get to the same spot, but at this point, given the regulations and the speed at which these regulations will come into compliance, that penetration shape will change and that shape will have a direct impact on sourcing the resources necessary for keeping the system reliable. So I think the more of a comment is I would really appreciate if the team can in the final adoption at a workshop or whenever we do that final results indicate those ideas would be really helpful just for the conversation around reliability and planning. Any questions on that? Are we generally tracking that point?

MR. COOPER: That makes sense, yeah.

VICE CHAIR GUNDA: Yeah, great. And I think I wanted to also just support Nick, the decision that you shaped on the planning scenario using the CARB's zero emission appliance regulation, I think really supportive of the argument you provided that is a more or less reasonable to occur. That's how you're thinking about this.

So I think a couple of comments on that. Given on one hand we are planning for reliability and making sure we quickly build as much as we can on the system side, but given the rate impact that it could have and how do we optimize that, really recommend bringing back to either an informational item at a Business Meeting or however when the CARB's regulations are already actually done and if there's a significant departure from this, having some way of updating those numbers in a mid basis. And finally, I think on the gas side, you also laid out for the gas system planning, looking at a more conservative approach. I feel like that's very prudent given the overarching transition on petroleum natural gas and electricity. There's so many uncertainties and keeping the system reliable at large to provide the confidence that we can get through this in a reliable fashion. Really important, really support that and look forward to hearing stakeholder inputs into it. We finalize the forecast. So I'm just generally really thrilled with all of your work. I could ask a million questions and Ingrid probably like you already asked that question before.

It's such a dense material to digest this, but really thrilled with all the work and look forward to having some offline conversations. And with that I'll pass it to Heather.

MS. RAITT: Great, thank you so much.

So it doesn't look like we have any questions, but I'll just go ahead -

VICE CHAIR GUNDA: And I think we might have a comment. We might have one Q&A.

MS. RAITT: Yeah, it's really just, yeah, it's a comment. Well, I'll go ahead and read it for us.

So in the newest 2023 IEPR cycle, we are providing four substation allocations to the CAISO for their transmission planning. These include the usual summer peak, but also three other snapshots across the year to provide better inputs to the CAISO for off peak assessments.

So anyway, thank you for that Mike. So not seeing any questions beyond that, I think Cynthia's off the hook.

And just thank you again, Ethan, Nick, and Ingrid. Those were really comprehensive presentations. Really appreciate all the work that went into them.

And so we'll move on to the next part and to hear about behind the meter distributed generation and storage. And we'll start off with Alex Longsdale. Go ahead Alex.

MR. LONDSALE: Thanks, Heather. Good afternoon, Vice Chair, Commissioner, Advisors, Stakeholders, members of the public. I'm excited to be here today alongside my colleague Mark Palmere, to present our 2023 distributed generation forecast. Next slide.

The presentation is broken up into three key segments. First, I'll present our forecast framework for the 2023 forecast cycle. I'll then hand things over to my colleague, Mark Palmere to present our annual forecast results. Last but not least, I'll present updates to our non-residential and residential behind the meter hourly storage forecasts. Next slide.

And without further ado, I'll now present the forecast framework. Next slide

For 2023, our distributed generation forecast team has implemented new methods for determining historical behind the meter distributed generation capacity, resulting in slightly lower estimates of PV capacity and higher estimates for energy storage capacity. We've also implemented a new market adoption model, commonly known as dGen as well as a standalone storage model.

Last but not least, we've also updated our behind the meter energy storage charge and discharge profiles, which I will present later today. Along with our methodological changes, we've also updated key incentives and policies in our forecasting framework. Starting with the net billing tariff. The net billing tariff for NBT was adopted by CPUC in late 2022 as a replacement for NEM 2.0. This went into effect for interconnections beginning in

April of 2023.

In addition, we've also incorporated updates to the federal investment tax credit. The most recent extension is part of the Inflation Reduction Act for IRA and has now extended the tax credit through 2034. The tax credit provides a credit of up to 30 percent of installation costs for behind the meter distributed generation resources. Next slide

For our forecast, our team leverages four models to predict growth and distributed generation capacity resulting from retrofits and new construction. Previous CD forecast tools did not distinguish between standalone and paired adoption for retrofits. The following table highlights our current suite of forecast modeling tools. The first column identifies the distributed generation installation type, which includes retrofit and new construction. The second column includes the name of each forecast model. Columns three through five identify the types of distributed generation configurations that the model is capable of forecasting. DGen, the first modeling tool listed in this table, is a market adoption model capable of forecasting distributed generation retrofits for standalone solar PV and paired solar PV and energy storage systems. Standalone storage is not considered in dGen as this tool is intended to compare the economics of installing solar PV and solar PV plus storage. CEC staff presented more details on this tool at the August 8th DAWG meeting alongside NRA and encouraged folks to review slides from this workshop.

The second tool listed here is simply referred to as our standalone storage model, predicts growth and adoption of standalone energy storage systems. It is a linear regression model which predicts adoption of standalone systems based on forecasted energy system costs.

Next we have forecast tools which were developed to account for the installation of distributed generation resources for new construction. Both models adhere to the 2022 California California Energy efficiency standards. As shown in the table 2022 energy code only requires energy storage installations for the commercial sector. Thus for single family residential construction, we're not forecasting additional energy storage capacity. Next slide.

The following table lists the inclusion and exclusion of several renewable distributed generation programs in our current forecasting framework. Before discussing the table, I'd like to define terms from this table. When I'm referring to the economics forecasts, I mean that the program requirements and the economics related to adoption are factored into the forecast. And for compliance-based forecast, this adheres to Title 24 requirements and does not directly account for the program's requirements or economics associated with adoption. As shown in the table, the current forecast includes economics and compliance -based projections for the net billing tariff. The dGen model includes an economics based forecast for retrofit DG systems interconnected under NBT since it factors in the tariffs requirements, namely TOU rate participation and ACC export as well as ACC adder values into the forecast calculations for net present value and payback periods, both payback periods and net present value are important measures which affect behind the meter distributed generation capacity in our forecast.

Furthermore, it's assumed that single family homes adhere to Title 24 requirements and will interconnect under NBT. Thus the forecast includes the compliance based forecast the systems interconnected under this tariff. The next program listed in this table is virtual net energy metering or VNEM. VNEM does not include an economic space forecast of this tariff. And I'll explain more about that in the following slide. However, the Title 24 commercial forecast implicitly accounts for new construction considered multi-tenant spaces. Thus growth and distributed generation capacity interconnected under VNEM is indirectly captured in our forecast. Furthermore, dGen does not model

DG adoption under the NEMA or Net Energy Metering Aggregation tariff. More details regarding this exclusion are provided on the following slide. With that being said, new construction captured by our four space projections indirectly accounts for DG adoption under this program. Current and past new construction projections do not include specific breakouts for multimeter, multi-tenant and single meter single-tenant spaces. Staff understand that refinements and identification of these construction types are likely required based on the ongoing VNEM and NEMA proceedings. Next slide.

Excluded programs. So starting with VNEM, solar plus storage retrofits to existing buildings aren't forecasted due to owner tenant barriers for adoption. That is in the dGen model. We don't consider an owner purchasing a distributed generation resource where the benefits go to the tenants. We're unable to capture this type of relationship in our current adoption models. Moving to NEMA, adoption is not considered by our model framework due to the complexities associated with modeling a distributed generation resource intended to reduce electricity cuts costs dynamically from multiple meters. It's important to note that CPUC has released a proposed decision on August 2, 2023 to revise VNEM and NEMA programs.

Moving to community solar. Forecasted adoption of community solar is a challenge to include in the current forecast models. Current renewable energy subscription programs are under review by CPUC and may be replaced in the ongoing consolidated community solar proceeding. CEC staff will consider ways to include renewable energy subscription programs in our future forecast based on the outcomes of the consolidated community solar proceeding.

Last, but not least, we have the renewable energy self generation bill credit transfer or RES-BCT. CEC forecast tools aren't configured to forecast adoption of distributed generation where the bill credits are shared across multiple billing accounts. This program also has a statewide capacity limit of 250 megawatts and closes thereafter. Thus, there's limited growth in this program, but we'll continue to monitor it and include the interconnected systems in our historical capacity data. This concludes my overview of our forecast framework.

Mark Palmere, our lead forecaster, will now present annual forecast results. Thank you.

MR. PALMERE: Thanks, Alex. Good afternoon, everyone. My name is Mark Palmere, and I'm the lead forecaster. As part of the overall forecast.

I'll be talking about the updates made to the annual forecast inputs as well as going over some high level results. Slide, please.

One key input we updated is installation cost. To estimate the cost of solar, staff used CPUC's adoption of $3.30 per watt as the current cost of installing a residential solar system in California in the year 2023. Staff then used NRELs annual technology baseline data to model the rate of change in costs throughout the forecast. The ATB was also used to calculate the discount rate of commercial installation costs. For 2023, our value there is $2.15 per lot. And as you can see, this is forecast throughout the entire period of our forecast. And by 2040 the last year of the forecast it decreases to $1.65 per watt for residential and $1.22 for commercial. Slide, please.

We have also updated the electricity rates used in our forecast. The base year rates are reflective of that year's electricity rates. In this case, our base year's 2022. TOU rates escalate in accordance with the 2023 electricity rate forecast. The graph to the right shows a sample rate escalation used in our model, in this case SCE's rates throughout the forecast period. And also note that the model's payback and net present value calculations do also take into account the updated NBT decision. Slide please.

And these give us monthly savings calculated by our model that line up with the electricity rates. As an example, here is a sample hourly electricity rate forecast. In this case SCE's TOU-D-4-9 residential rate from the months of October to May. Showed in three years our base year of 2022, 2030, and 2040, which is the last year of the forecast. And you can see how the rates increased over the forecast period. And meanwhile, the graph on the right shows the average first year monthly bill savings, which is calculated by our model as an intermediate output that helps determine adoption. And basically as a result of these increase rates, the average monthly savings also increases dramatically from 2022. Well it starts in 2024, but from 2022 through 2040. Slide please.

Another update we made was to the average size of residential Title 24 installations. Staff acquired permit data from the Energy Commission standards compliance - standards compliance branch to estimate average residential PV compliance installation size for new homes by forecast zone. These sizes were higher than previously estimated leading to increased compliance-based solar PV capacity in the residential forecast. Slide please.

Now I would like to go over the annual results. Slide please.

First PV, our forecast shows steady adoption rate until the mid 2030s. Capacity additions level off after 2034, as you can see. And that's due to the elimination of the Investment Tax Credit incentive or ITC. Slide please.

These results are greatly influenced by the input updates I previously mentioned. Updating the forecast cost installation as well as electricity rates affected the payback period calculation, which is another immediate output of our forecast. Due to lower costs and higher rates, the payback is forecast to decrease until the ITC is phased out in the mid 2030s, at which point it jumps up for a little bit before beginning to decrease again. Slide please.

Looking more specifically at solar installations, we see that the majority of installed solar is forecast to be retrofits of existing buildings until the ITC incentive expires. This is because Title 24 new home installations are based on compliance, therefore, they do not level off with the expiration of the credit as the retrofits do. However, looking overall throughout the entire forecast to 70 percent of added capacity added PV capacity comes from retrofits. Slide please.

Now let's look at the breakout by planning area. The majority of PV capacity is in IOU territory, mainly reflecting a similar majority of customers in that territory. Ninety-two percent of cumulative capacity through 2022 is in IOU territory. And it is forecast to decrease slightly by the end of the forecast, but still be about 88 percent by utility throughout the forecast PG&E's total capacity is forecast to jump from 6.8 gigawatts to 14.7, SCE's from 4.5 gigawatts to 12.8, SDG&E 1.8 to 3.5, LADWP 0.5 to 2.1, SMUD 0.3 to 1.0 and all others - the aggregation of all the other utilities from 0.3 gigawatts to 1.2 in 2040. Slide please.

Another informative breakdown is solar by pairing. The payback periods in our model tend to be lower for solar systems that are paired with a battery and it is seen as an important tool in reducing electricity sales. Reductions in installation costs of energy storage coupled with rising electricity rates results in an increased share of paired DG adoption through 2032. However, the share of standalone solar PV increases in later years due to the ITC expiration, which in our model affects storage more than it affects solar. Slide please.

And that brings us to overall storage results, which similar to PV increase at a steady rate until the elimination of ITC in 2034. The adoption is actually greater than PV as changes to excess solar compensation in addition to the cost and rate factors mentioned in the previous slide, all incentivized storage adoption. In fact, the average annual growth rate throughout the forecast is about 30 percent for storage compared to about 14 percent for solar. Slide please.

While standalone systems make up the majority of PV capacity, standalone storage is relatively rare. Over two-thirds of currently installed storage capacity is paired with PV systems and that number is forecast to be 83 percent in 2040. However, there still is growth in the standalone sector as it is now also eligible for the ITC resulting in increased adoption rates also until 2034. Slide please.

And finally, I'd like to share storage results by planning area. As with PV, the majority of capacity is in IOU territory. So for storage it's actually an even wider gap as our base year numbers indicate 95 percent of installed storage capacity being in IOU territory. That is forecasted drop to about 90 percent by 2040, but it is still a strong majority. And this concludes our summary of the annual forecast. I'll now toss it back to Alex Lonsdale for a breakdown of hourly storage results. Alex.

MR. LONDSALE: Thanks for your presentation, Mark.

As indicated, the following slides will cover updates to our hourly non-residential behind the meter storage profiles for the 2023 forecast. Next slide.

For the 2023 forecast cycle, our overarching methodology remains unchanged from previous demand forecasts. For 2023, our behind the meter non-residential storage profiles are from CPUC's upcoming self-generation incentive program, or SGIP, energy storage impact evaluation.

Our methodology is as follows. First, we develop our annual behind the meter distributed generation capacity forecast. We then map this capacity forecast to SGIP evaluation building types. We then apply normalized SGIP profiles to our capacity forecast, and then aggregate the spatial temporal resolution to match the forms that we post as part of the IEPR. Our decision to use these profiles in our forecast is primarily based on data availability as well as the SGIP data sample size relative to total interconnected systems in California. In the following table, you'll net two storage configurations paired with solar PV and standalone.

And the second column is an estimate of number of non-residential behind the meter storage systems by end of calendar year 2022. In the third column we have the average SGIP evaluation data project sample size. You'll note that the SGIP data sample size is about a third of all the interconnected systems estimated from interconnection data. Please note that the count of systems is not representative of the distribution of capacity by configuration. Standalone storage makes up about 70 percent of total behind the meter non-residential system capacity in 2022.

Next slide.

Methodology refinement. So while our overarching methodology hasn't changed, CEC's new distributed generation capacity forecast tools distinguish between standalone impaired behind the meter storage adoption and capture this distinction in hourly profiles more precisely. Please note for hourly charts in this presentation, positive megawatts indicates energy storage discharge negative megawatt values indicate charge. The hour index is always hour ending Pacific Standard Time.

The chart on the left shows a typical July weekday storage profile in calendar years 2023 and 2026. There are three lines in this chart. The dark blue line is a total load profile. Standard blue dashed line is the paired storage profile and the light blue line is the standalone storage profile. The key takeaway here is that the aggregate CAISO profile changes through time as a share of standalone impaired storage capacity changes. As shown on the chart on the right, you'll note by 2026, the share of paired storage capacity has increased relative to 2023. This result is an aggregate profile with on peak discharge behavior, which more closely aligns with paired system profile, resulting in a less percentage of energy charging overnight. Next slide.

The following chart compares the 2022 and 2023 non-residential behind the meter storage profiles for typical weekdays in July and December in calendar year 2035. The first chart for typical July weekdays shows how increased paired storage adoption results in more midday energy charging, whereas the 2022 forecast did not explicitly capture growth and adoption of paired or standalone systems. Thus, the profile shape is the same as calendar year 2022, and assumes most energy is still charged overnight. The chart on the right compares December 2035 average hourly profiles. For the 2023 forecast, you'll note that the total energy discharge during the on peak hours is lower compared to July and is of a more fixed rate through the traditional on peak hours. Growth impaired storage system adoption by 2035 results in an increased share of energy storage charging when solar generation is available. The reduction in total energy charged overnight from hour ending 21 to six from CED 2022, CED 2023 as follows. For July weekdays, the reduction in energy assumed to be charged overnight is 57 percent, and for December weekdays is 51 percent. This speaks to the refreshment of updated self-generation incentive program data, capturing most recent charging and discharging behavior amongst a larger pool of energy resources interconnected to the grid. Next slide.

VICE CHAIR GUNDA: Hey Alex?

MR. LONDSALE: Yeah.

VICE CHAIR GUNDA: Hey, just a quick question on this one. Sorry, didn't mean to interrupt. Basically y-axis here going from negative 400 to 300, what is that magnitude from the previous slide? I'm just think what is it indicative of or is it just a directional number?

MR. LONDSALE: Sorry, I'm not sure I'm following your question. These values are based on discharge rates for measured systems. So the typical discharge per rate of capacity -

VICE CHAIR GUNDA: It's just - Okay, it's the pool of the data that you had. Is that what it is?

MR. LONDSALE: Correct.

VICE CHAIR GUNDA: Okay. Okay, thank you. So it's not kind of scaled to the forecast results, it's just basically -

MR. LONDSALE: This is -

VICE CHAIR GUNDA: Looking at -

MR. LONDSALE: No, this chart here is scaled to the forecast capacity. So we have our normalized profiles on a base tier where you have your normalized rate of charge or discharge as a percentage. So some megawatt measured system from the SGIP incentive program has a megawatts discharge or charge value in a specific hour and its rated capacity. And all that data is brought together and develop average normalized profiles from all the pools of resources from the SGIP data. We then use those normalized discharge rates of charging and energy discharging and scale them to our forecast capacity. Does that make sense?

VICE CHAIR GUNDA: Yes, but I'm not completely tracking in the sense that if we go back to slide 21. Right. So that's kind of the totality. So if I'm understanding this right, we are in the 6,500 megawatts of cumulative capacity and this is in the 400 range. Can you explain that?

MR. LONDSALE: Absolutely. Yep. Absolutely. So average discharge rates are relatively low right now in terms of the data that we've seen for non-residential systems. So keep in mind the chart you're looking at right now, that is total statewide capacity, not by residential and non-residential. A bulk of the capacity in our forecast is actually in the residential sector. So you'll see in the following slides that I'm going to present when I transition to residential storage. You'll see that the energy charge and discharge values are higher in the forecast period because there is more storage adoption, like the percentage of all capacity is weighted towards the residential sector instead of the non-residential space in our forecast.

So you have to break this down to say maybe 30 percent of this capacity is applicable to the non-residential space. Then you have to break that out to, this is statewide results. We're looking at only IOU planning areas for an hourly forecast. So then decrement that another couple percentage points, and then you're looking at discharge rates on average that fall between and on peak hours, maybe 15 to 20 percent at most. So there's several factors we have to scale these numbers down to really come to what is the hourly value of energy charge or discharge.

VICE CHAIR GUNDA: Excellent. Thank you so much. Thanks for the clarification.

MR. LONDSALE: Yeah, I totally understand why you're asking that question from the charts and could have made that a little more clear. So appreciate your question.

Picking up where we left off with the CAISO September peak impacts. So revised capacity protections accompanied with refresh profiles results in greater systemwide peak productions, increased storage discharge during hour 19 in 2035 is approximately 58 megawatts and is indicated by the markers here in this chart. Next slide.

That concludes my overview of the non-residential behind the meter storage profiles. I'll now present updates to our residential behind the meter storage profiles.

For the 2023 forecast, again, our overarching methodology is the same. So staff used NREL's System Advisor Model to develop behind the meter residential storage profiles. SAM simulations are configured for a prototypical single-family home with behind the meter solar PV and storage. Several SAM parameters are modified to produce hourly profiles for the CED forecast. Solar PV and storage system size were selected based on CEC analysis of utility interconnection data. Single family home and annual electricity consumptions estimated from our revamped residential sector end use models. TOU rates were selected in accordance with the Net Billing Tariff. Hourly dispatch strategies are configured based on the assumption that systems dispatch during evening hours. Next slide.

Before I present our updated profiles, there are also other key assumptions that we need to mention. So past CED forecasts consider time of use arbitrage explicitly during the on peak hours. It's important to note that when scaling these assumptions to planning area projections, this resulted in large hour to hour changes in load, shown on the following slide. While it's assumed most energy storage discharge occurs during the on peak period SGIP impact evaluations suggests some discharge may be occurring outside of these hours. Furthermore, with the electrification of appliances and vehicles, it is probable that storage discharge will extend beyond traditional on peak hours. In result, staff developed and presented several profile scenarios to stakeholders at our October DAWG meeting. The following slides compare the preferred scenario profile to CED 2022 profiles.

Next slide. Oh, there we go. So this chart compares normalized profiles. It's marked 2021 forecast, but these are also applicable to the 2022 forecast, and these normalized profiles are indicated by the gold lines in this chart. Please note the Y-axis values here are kilowatt hours per kilowatt hour rated capacity and applied to all of the energy capacity within a given track. The first segment of this charge, PG&E, followed by SCE and SDG&E. The 2022 profiles suggests residential storage behavior is different after hour 21 amongst the IOU planning areas. Most notably the SCE profile had assumed energy discharge drops off completely by hour 21, whereas the PG&E profile had assumed continued dispatch until midnight based on time of use prices. Moving away from TOU on peak dispatch to a more general evening dispatch strategy results in more consistent assumptions across the IOU tax and may be more reflective of system-wide behavior through time. Staff see the need to continue to inform refinements to behind the meter storage profiles as more data in the space becomes available. Next slide.

The following chart highlights forecasted cumulative CAISO system-wide peak hour discharge for the 2023 forecast compared to 2022. There's actually slight decrease in discharging hour 19 2035 when compared to last year's forecast. This is a result updating our discharge rate allowance in the SAM model as well as similar total cumulative capacities by 2035.

Next slide.

The following chart compares CED 2023 behind the meter storage profiles to a historical CAISO Limited Energy Storage or LESR profile in 2022. This is utility scale storage. CED profiles include residential and non-residential sectors. The forecasted behind the meter energy storage net discharging calendar year 2040 surpasses the historical averages from the 2022 limited energy resource profile data. It's important to note that motivations for behind the meter storage in the forecast are optimized around end user goals to minimize bill savings through a blend of TOU arbitrage and peak demand shaving. Whereas utility scale systems dispatch based upon grid needs. While there are differences in motivations for discharging storage, there appears to be some convergence in charge and discharge behavior across BTM and FTM systems. Simply put both FTM and BTM systems are charging during hours of solar resource availability, and discharging the most during on peak TOU hours. Staff look forward to learning more from

CPUC's upcoming SGIP evaluation prepared by Verdant. These reports typically highlight storage behavior during grid constrained hours and serve as a basis for learning how BTM storage could be better utilized in the future, both from a GHG and load perspective. BTM systems have a great potential as a flexible load modifier and our forecast team understands the need to continue to track the space closely and think through how behind the meter storage profiles may change time. Next slide.

Next, I just want to give a special thanks to CPUC for helping us in acquiring the SGIP data, Verdant Consultants for providing the SCE data ahead of the report release. And, of course, the Distributed Generation Forecast Team, Mark Palmere, our lead forecaster, Bobby Wilson, who's joined our team this year as an energy analyst and forecaster. And last, but not least, Sudhakar Konala, who used to be our lead forecaster has rejoined our team as a forecast advisor and we're happy to have him back. Next slide. And of course, thanks to all stakeholders for their continued collaboration at DAWG, thank you Commissioners, public attendees for your time and attention today. And that is my presentation.

VICE CHAIR GUNDA: Can I just jump in, Heather?

MS. RAITT: Oh, yeah. Please do.

VICE CHAIR GUNDA: Thank you, Alex and Mark. I probably will sound like a broken record, but again just thank you, thank you, thank you. And how amazing of work you guys are doing in terms of just continuing to modify and improve the work. And thanks for acknowledging Sudhakar. It's really great to have him back on the team again. And also to Bobby thank you for your work.

I have a of very high level questions, comments, and kind of discussion. If we take a couple minutes here, Alex and Mark. I'm trying to look at this from a couple of different perspectives. So one is, I think Alex, you commented that towards the end, one element of it is just improving our forecasting to be able to provide the best available forecast to PUC and other lRAs for a grid planning perspective, right? So that's kind of an important element. So for the IRPs. The other element I'm looking through is what incremental opportunity do we have with behind the meter and DRD (phonetic) sources to support grid reliability, right?

So earlier this year when we adopted the load flexibility goal of 7,000 megawatts. We broadly framed that as three buckets. And I think I just want to frame that and then ask you a couple of questions to react. But we said about 3,000 megawatts of that 7,000 is going to come from load modifying. So it's primarily storage, it could be demand like DR whatever, it's like virtual power plants, not virtual power plants, but in some programs. And then you go towards, okay, once you reduce the demand based on primarily redesign, you now go into planning for your resource procurement. And there are some virtual power plants and incremental programs that come after that. And then we said between the load modifying and RA, resource adequacy, we can think of roughly 3,000 megawatts and then 4,000 of the megawatts were going to come for incremental even beyond that. So first question of clarity, how does the forecast treatment in terms of really articulating what's load modifying, what's RA, like virtual power plants and such in terms of those programs at PUC and other IRAs that are using behind the meter storage for a virtual power plant, for example, how do we avoid double counting? What is the current way of doing it? And how do we think about that?

MR. LONDSALE: So you're referring to, let me just make sure I understand the question correctly before I respond. So you're asking for how do we account for energy storage systems that are behind the meter, that are a part of virtual power plant and they have their own charge and discharge behavior. How do we distinguish that capacity from other behind the meter resources that may be strategizing around TOU arbitrage and peak demand shaving? Is that your question?

VICE CHAIR GUNDA: Yep. Yep, exactly. How are we?

MR. LONDSALE: Okay, so we don't currently have to be transparent. We don't currently have a way to, in our interconnection data, we overhauled estimating the behind the meter capacity, but we haven't had a way just yet to target exactly which interconnected systems would be virtual power plants, which ones would be enrolled in those sorts of systems. So that is not part of our behind the meter historical process. That's not something that's incorporated right now in terms of behind the meter, non-residential system. So if they're connected via a NEM interconnection agreement, if they're connected in any of those NEM buckets, then their capacity is factored into our hourly estimates of charge and discharge.

VICE CHAIR GUNDA: Got it. Thank you so much.

Mark, do you want to add anything? I saw you came off mute.

MR. PALMERE: Oh, nothing addition to what Alex said.

VICE CHAIR GUNDA: Thank you.

So, Alex, then I think just as a comment, as we continue to incorporate quantitatively some of the refinements, it would really appreciate clarify at some point in the near future here to really shed light on the intersection of the forecasting work. How does that support this paradigm of 7,000 megawatts of load flexibility goal we have, right? So how can we think about this is what's load modifying element? This is what's virtual power plant maybe? I think it's very small right now. The virtual power plants, I think it's tens of megawatts right now. I think it's 30 or 40 in PUC, but I just want to make sure that we put a pin on estimating that.

And then second, I think just looking at the forecast, as Mark mentioned, the forecast magnitude hasn't significantly changed since the NEM 2.0 to NEM 3.0 and whatever. Also noted that there's a lot of mathematical changes that we had. Setting aside that the numbers, the total addressable market, right? If we think about a hundred percent roof space in California for all existing buildings. What is the - where are we plateauing based on our modeling right now? I think what I see is 30-40 percent maybe. I don't know if you can comment on that. And what do you think is stopping that? I mean I'm sure the answer, it's the payback period, but anything else that you could shed light on would be helpful.

MR. PALMERE: Yeah, for sure. Yeah, so we've been doing a little looking into that a little more and it looks like, yeah, our model, the maximum market share as they define it does as you say, have a lot to do with payback period. And so the numbers we're getting as when the payback period is lowest in the forecast, the max market share is about 60 percent. So that's the as things are now, the limit that we're looking at. And yeah, as I said, a lot of it has to do with as the model is developed, that is the limiting factor where as the payback period gets lower, the maps, the potential goes up. But obviously in reality there are other limitations. I think a lot being that, and this is something we're working on modeling better, is the different types of home owner or home residences like rentals and multifamily buildings. Obviously there are more barriers or financial disincentives for adoption there compared to a single family owner occupied home. Yeah. So that's something we're trying to definitely working on better capturing. But other than that, so yeah, I think there's that as a inhibition and as you mentioned the payback period, those are the two that we're noticing. I don't know if Alex has anything to add.

MR. LONDSALE: I think Mark, I think you highlighted the larger buckets. I think that the owner-tenant relationship, a lot of people may rent their spaces or there's existing multifamily buildings right now and with the resource mostly benefiting all their tenants. There might be some barriers under a virtual NEM situation for retrofits where you're really not maybe going to tap into that market just because there's not a large enough incentive for the owner to recuperate their investment because the benefits are going to the tenants occupying the space on their electricity bills. They are receiving the bill credits for the energy generated on top of that roof. So I think that's part of it. And I think, so renting spaces, right. We need to, I think a refinement we can look through is how many single family homes are also being rented out. They're purely for rental space because the motivations to install, in our model, the motivations to install a distributed generation resource, people want to see a payback on that resource.

They want to be their recuperating their investments. And I think with the owner-tenant relationship, that is a classical barrier to getting more PV on all the rooftops in California. I think there's another sliver of that bucket, and that is just not all homes are optimally built for solar PV. And I think this is a smaller bucket, but just addressing it, there are homes dispersed throughout California in different climate zones and there are different shading and different roof orientations that might not be optimal for solar PV. So I'm thinking about more like the mountain communities and things, and that is something that's factored into dGen. There is a whole report that talks about the technical potential based upon Lidar data and irradiance data of how much irradiance can you get in this area? Is it economical to install solar on these roofs? I think in California a large part of roofs are well suited for solar PV, but I just wanted to mention that as a slim bucket where you're going to start to decrement the total available roof space a little bit from those sort of considerations.

VICE CHAIR GUNDA: Thank you, Mark and Alex.

Alex, just a follow up on that one then. So between the technical potential, just reiterating this between the technical potential in California behind the meter solar and also storage systems to what we economically cap at or hit the ceiling. And if I heard Mark, it's about 60 percent, then what part of that technical potential do we cap at, roughly.

MR. LONDSALE: Based on the current ceiling that we have in our model, that's correct. We're assuming based on, so there's studies and that was part of the DAWG meeting we talked about with NRELs. There were surveys conducted based upon market payback periods for solar PV. And based on the survey data that we have and integrated into our modeling framework and our assumptions, given a payback period of approximately six years, you're going to saturate a market of 60 percent.

So I think another layer to this that we're talking about and about a six year payback period and saturating the market is this complexity about who can afford to make the financial investment on the front end for these systems. So we're thinking not everyone is upper middle class or middle class - targeting those buckets of making sure that the right incentives are available for disadvantaged communities, lower income. So when we talk about the broad scale of just everyone installing solar, I think it's really important to consider income buckets as well. And we do have a version of the model that we're working on to consider and more target, let's think about adoption, but we need to make sure we're more stratifying these adoption buckets and technical potential based on financial ability to make the upfront investments on distributed generation resources to make sure that that is accurately reflected in our forecasts moving forward.

VICE CHAIR GUNDA: Great. Okay.

So one other theme here, just thinking through, so in 2020 when we had the reliability crisis in California, there's a couple of things we looked at. One is obviously we had supply constraints and the extreme heat, but we also had some monotonal conditions that decreased the overall production of generation from solar bulk solar very rapidly in the middle of the day.

So one of the questions that was raised was, what happens to behind the meter storage, right? And behind the meter solar during that time as you - if you have a couple of cloudy days, monsoonal days that are coinciding with high heat, trapped heat. How do we think about that potential loss of generation? Again, I know that's not the forecasting and the planning piece, but it might be washed off in a one in two planning mode. But I really would like to put a pin in thinking about the potential volatility, volatility on the system that we might see because of behind the meter PV. And to some extent the storage might compensate for that - behind the meter storage, but I would really like us to continue to explore that team as a part of reliability work.

MR. LONDSALE: Definitely, and I don't want to say too much about that right now. I think that there's still scoping work, but I understand that there's a lot of stochastic modeling that we're working on and I think that some of the stochastic modeling approach about variability and generation throughout the week or throughout the month and thinking through variability and generation profiles for PV. Also we need to consider a lot of these systems in our forecast right now appear to be charging off of solar generation resources. So factoring that in as well. I think that there's a lot of analysis to be done in the space that you're describing.

VICE CHAIR GUNDA: Yeah, thank you.

So in closing, Alex, thanks to you and Mark and the team Bobby and Sudhakar. I do also want to recognize your slide 32 in a way you kind of talked about how the limited energy storage, but also that the behind of meter storage profiles kind are similarly charged and discharge while the magnitudes are different. And I think it's an interesting thing that whether you're coming from a grid side bidding perspective or the TOUs, the arbitraging of this resource is coming maybe hopefully to an and would love to follow that chain of thought as well.

So overall incredible work, thank you and look forward to the stakeholder feedback on how to make this better. Thank you.

MR. LONDSALE: Thanks, Vice Chair.

MR. PALMERE: Thank you.

MS. RAITT: I'm not seeing any questions from Zoom or participants via Zoom.

So thank you Mark and Alex so much for those presentations. And so Commissioner, if you're okay, we'll I think we're ready to move on to public comment. Okay, comment.

So I see that there are two hands raised, so if anyone on Zoom would like to make comments, just use that raise hand feature to let us know that you want to comment. And if you're on the phone you can press star nine and that will let us know that you want to comment. And so we'll reserve three minutes per person, just one person per organization place. And let's see.

So the first one is Yu Zhang from PG&E and so you may need to unmute on your end. Go ahead.

So I don't know if Yu Zhang unmuted, but we can come back to you and we'll move on to Brandon Serna. You want to go ahead and unmute?

MR. SERNA: Oh, apologies. I think I raised my hand by accident.

MS. RAITT: Okay, no worries. Let's see, if you had a question, I mean a comment. Excuse me, maybe that was an accident as well. Anyway, and if anyone else has comments to just raise your hand and if you're on the phone again, press star nine and they'll let us know. Otherwise we'll just give it another moment and we will close public comment.

Alright, not seeing any hands up. Vice Chair, I think it's back to you.

Oh, actually, let me, if I may, I'm sorry to interrupt. Just mention again that written comments are welcome and due on December 1st. And then we have, as the next slide shows, we have another workshop coming up on December 6th for the rest of the forecast results. And so hope you all can make it for that. And that will also be a remote workshop.

And with that, if you had any closing remarks, Vice Chair.

VICE CHAIR GUNDA: No, that was a great day. I just love the kind of wonderful work that's happening. Heather, thank you to you and your entire team for facilitating and that IT team and support team. So yeah, I don't have any further comments.

Thanks to all, and thanks to the public for participating and look forward to future conversations on this. With that, happy to adjourn.

(ADJOURNED AT 3:37 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 9th day of January, 2024.

Elise Hicks

ELISE HICKS, IAPRT CERT**2176

CERTIFICATE OF TRANSCRIBER

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

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

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

Martha L. Nelson

MARTHA L. NELSON, CERT**367

January 10, 2024