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CALIFORNIA ENERGY COMMISSION

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IEPR COMMISSIONER WORKSHOP

ON THE 2016-2026 CALIFORNIA ENERGY DEMAND

REVISED ELECTRICITY DEMAND FORECAST

CALIFORNIA ENERGY COMMISSION

1516 Ninth Street

First Floor, Charles Imbrecht Hearing Room

Sacramento, California

THURSDAY, December 17, 2015

10:00 A.M.

Reported by

Shanalee Gallagher

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I N D E X

PROCEEDINGS

December 17, 2015 10:00 a.m.

MS. RAITT: Good morning. So we're going to go ahead and get started here. Welcome to today's IEPR Commissioner workshop on the 2016 to 2026 California Energy Demand Revised Electricity Demand Forecast.

I'm Heather Raitt, Program Manager of the IEPR. I'll go over the housekeeping items.

There is a bathroom on the first floor.

If there's an emergency and we need to evacuate the building please follow staff to Roosevelt Park, which is across the street diagonally.

Our meeting is being broadcast by WebEx Conferencing System, so we are being recorded and there will be a WebEx recording out in a couple days and a written transcript in about a month.

We plan to have presentations this morning and then break for lunch around 11:45 and then have more presentations in the afternoon, and public comment at the end of the day.

If you'd like to make public comments please fill out a blue card, and when it comes time you can come over here to the podium and make comments.

For WebEx participants, you can use the raise a hand button to tell our WebEx coordinator that you'd like to make a comment during the public comment period and for phone-in participants we'll take comments at the end.

Materials for the meeting are at the entrance to this room and available on the website. Written comments are welcome and due on December 31st.

Commissioner McAllister has some opening remarks.

COMMISSIONER MCALLISTER: All right. We are testing out our new audio system here so hopefully it works better than the last one.

So I'm Andrew McAllister, the lead on this year's IEPR, also in energy efficiency. Very glad that Chair Weisenmiller could be with us today as well, because we all know the forecast is really one of the absolutely foundational things that the Commission does and it's very key, particularly key this year and in the near future as we transition to new and better ways and more granular ways of doing the forecast, and as we lay the foundation for implementation of SB350, a big, big deal for the state, increasing scrutiny of the forecast process, methodology and outlet. And at the same time, some uncertainty about lots of potential data, lots of information that could be brought into and utilized in today's day and age, but obviously that increases the possibility for us to gather all the different pieces of information that come into planning for the future and really take a long term vision of what we want to do not just in this forecast but in the subsequent forecasts every couple years as we approach our quite impressive goals.

I want to highlight. You all know Paris came and went and we ended up with some, I think, groundbreaking agreements. And not that the content of those agreements was particularly aggressive from California's point of view. I think we have goals that are appropriately aggressive for us and are trying to lead. The Governor was there, a number of members of the Legislature were there, and trying to really up the profile of California as a state but bring others along at the regional, subregional level.

And a lot of the roads of the conversations that California is leading lead back to the forecasts. It's not exactly Rome but it's something like that. And it's really key for us to meet our own goals, and as a leader in the state we need to lay a proper foundation so that we can actually hold it up and say look, here's how we're doing things and here's the road that we've mapped out and here's how we're traveling along it. And other states and regions and nations actually come along.

I was just in D.C. for the entire week up to today, and really it's just everybody's working in California. It's really the heightened profile we have coming out of Paris is palpable. President Obama is doing a lot and really was key to getting that agreement done, and the Clean Power Plan and big pieces of that at the national level are really important, but a lot of the reason he is able to go as far as he has gone is because California is there, kind of showing it can be done. And the Clean Power Plan is the big topic of conversation.

It's kind of funny in California it's like oh yeah, it's great, but that's not really what's grounding us. If we get our own goals, we're going to knock the clean power plan goals out of the park.

So I guess what I'm saying is the context of the forecast is much broader than maybe day to day many of us realize and it is foundational for the state across our agencies with the Air Resources

Board, the PUC and the ISO, and so working together we're going to show whether it can be done, and the forecast is one of the records and the text for documenting how it is getting done now that it's getting done.

So as we look forward that continuity from forecast to forecast (inaudible) retrospectively and working out the methodology to get where we need to go. And as the context changes in the state it's really important to keep in mind as we work through this particular forecast.

So with that, I'll pass it on to the Chair.

CHAIR WEISENMILLER: Thanks to everyone for being here today. As we get close to the holiday season I was going to just reflect back on a couple things as we move forward.

First, I remember early on in my energy career talking to Dan Luden, he was recounting a tale of a meeting between he and David Brower and one of LVLs luminaries, and the LVL luminary had assured them that you could more easily change the rate that the Earth moved around the Sun than you could change the rate of growth for electricity.

So having said that, looking forward at this stage, when you look at our forecast, you're starting to see ways we could really start moving the needle quite a bit. Certainly looking at 802, looking at 758, looking at 350, what we're really trying to do is convert a different vision and certainly the vision that was articulated by Art Rosenfeld and Tom Graff in the 70s that you could come up with actions and trace back through the forecasting pool here to basically change the electricity future.

So having said that, we're sort of going through pretty much on very detailed in the programs. As you look, huge changes in where we're looking at the forecast going at this stage.

Obviously, we're in some respects running out in front of the data we have, and I think basically the message in part next year is going to be more of a pause externally on the forecast because we really have a chance to really go through fundamentally back through some of the underlying data, back through the methodology, and really be enhanced so that as we go forward we're in a position that we're very comfortable with these projections.

And certainly there's been some pretty significant, you know, PUC's NAM decision this week, the extensive solar tax credit, one of the real big drivers in our forecast is the relatively rapid growth in portable tanks.

So again I think as we go forward we have a chance to really get more data on cost and what's going on on the implementation but it's really changing things quite a bit.

So as we go forward, next year we'll be more or less recycling what we come out with from this year, but the following year after that we're really going to be digging in pretty deeply these issues. It'll be pretty exciting at that point.

I would indicate one of these which again just so everyone's pretty clear on is that as we are going through the process we've been really staying in pretty close communication with the PUC and CalISO so that we can continue to really sync up forecasts across the agencies.

So anyway, thanks for being here and it should be an exciting day.

COMMISSIONER MCALLISTER: Thanks for pointing out the PV that came out from the PUC on net metering and I guess the preliminary read is that, well, it's great for solar and I think they deferred in that way some of the key discussions to the time-of-use perform because that's where a lot of the utilities are going to argue that they need to get their distribution charges covered. So this conversation, we’re in the middle, it’s a PD that’s not voted out but a lot of stuff’s going to change here in the next few years and the next full IEPR is going to put us in a situation where we have more information and can be a little less in the dark about what the future actually holds in terms of the economics about this.

CHAIR WEISENMILLER: Exactly. I guess we should be clear that obviously this forecast doesn’t reflect last week’s decisions, and in fact, as you pointed out, the PUC proposed decision is close to final and the time-of-use rate decisions are still being worked through.

So there’s a lot of other pieces that by the time we dig into these things much more seriously there will be a much better understanding of the record.

MS. RAITT: Thank you. So our first speaker was going to be Chris Kavalec, but unfortunately he isn’t available to be here today, and so we have Nick Fugate and Tom Gorin are going to be giving his presentation in his place.

MR. GORIN: Good morning, Commissioners. For the record, my name is Tom Gorin, not Chris Kavalec.

Chris is on injured reserve, hopefully he’s on the phone and can answer the hard questions. So Nick Fugate and Cary Garcia and myself are going to try and muddle through the presentation. We spent about four hours with him yesterday going over it, and I think we understand most of it.

For those of you that don’t know me, I’m a retired annuitant here at the Commission and I’ve been involved in the forecast in some capacity since 1978 so I have a little bit of history of what is going on here. Except how to work a computer.

[Next Slide]

So the revised forecast has a new geographic scheme which tries to adhere more closely with the ISO balancing authority regions which Chris worked with the ISO in developing.

Results, the baseline consumption is down significantly compared to the 2014 forecast update, because we have new standards in this forecast and adjustment to the 2013 Title 24 standards for existing buildings.

There is a much greater decrease in electricity sales and peak demand because of higher PV penetrations in this forecast.

We also include additional achievable energy efficiency savings for IOUs based on the most recent potential study, and for LADWP and SMUD to produce managed forecasts for them.

COMMISSIONER MCALLISTER: You said this does include downward adjustment for some of the work that we've been doing through Title 24 on existing buildings?

MR. GORIN: Yes, I believe so.

COMMISSIONER MCALLISTER: Okay. So maybe as you go through this maybe some detail about to what extent the existing buildings are included, whether it's 758, Title 24 per se, or where the model of savings from those initiatives come from.

MR. GORIN: Maybe Nick can address that or Chris.

COMMISSIONER MCALLISTER: Okay. Just when we get that on the table. If we can't get all answers today that's fine.

MR. FUGATE: Maybe during the efficiency presentation.

MR. GORIN: Nick is going to handle the efficiency presentation.

COMMISSIONER MCALLISTER: Okay.

[Next Slide]

MR. GORIN: So this is a diagram of our

energy demand modeling system that has been around for probably the past ten years. On the far left and far right we have two new elements of it, though.

On the far left there’s EV and natural gas forecasting model it’s done by (inaudible) and I believe that workshop was two weeks ago to go over the results of that.

And on the far right there’s a self-generation model which Ashish Gautam is going to go over later today.

The other parts of this are essentially the same as they have been in the past. The disaggregation of residential, commercial, ag and water pumping, TCU Street lighting and industry.

Going to the summary model we go to the peak demand and hourly load model and come out with a forecast for peak energy and sales.

[Next Slide]

We developed three baseline demand cases.

High demand case with higher economic and demographic growth, high climate change impacts, high EV case, lower electricity rates, and less self-generation. And the higher economic growth came from the global insight optimistic forecast.

The low demand case was lower economic and demographic growth, no climate change impacts, low EV case, higher electricity rates, and more self-generation. The economics came from Moody's economic baseline forecast and Moody's population forecast.

Moody's population forecast was also used in the high demand case.

The mid demand case -- actually, the low demand case was the Department of Finance population forecast, I believe, which is lower than Moody's.

The mid demand case is assumptions between the two cases. On the next round of forecasting we're going to try and get Moody's to develop a high case for us so it would be more consistent with the mid and low cases.

[Next Slide]

These are a graph of the electricity consumption. The new revised mid case is about 9,000 gigawatt hours lower than the 2014 update by 2025, which is due to the existing Title 24 standards for existing buildings, new Federal standards for water using appliances, and a somewhat lower population forecast.

You will note that the change in the slope in history that the chairman was talking about from 2006 we're showing a little higher growth. In the most recent growth it’s definitely lower than the growth rate from 1990 to 2006.

[Next Slide]

The electricity sales forecast is almost 20,000 gigawatt hours lower than the 2014 update. This is by a greater assumption on PV introduction and self-generation. And the bigger spread in this is caused by a bigger spread in PV adoption assumptions which Ashish will talk about later.

[Next Slide]

And baseline noncoincident peak forecast is also about 7,000 megawatts lower than the 2014 update by 2025. This has to do also with the PV adoptions.

The difference between 2015, this value in history the weather normalized 2015, this was what the 2014 update was when 2014 was the last year history.

[Next Slide]

Baseline consumption per capita is projected to decline slightly until probably about 2020, and then the slight increase is due to an increase in heating consumption assumptions.

[Next Slide]

This is the new geographic scheme.

Planning areas are now corresponding more closely to the TAC and balancing authority sales. In the past you had old utility planning area definitions, which in the new scheme are more and more obsolete.

We increased the number of forecasting zones to 20. The new zones are trying to approximate the ISO transmission zones within the utility service areas.

And we’re striving for some continued refinement of the geographic areas in the granularity, but we are limited somewhat by the forecasts of economic drivers that is primarily only available at the county level. There are some counties where we can parse out metropolitan areas within that county but most of the economic data is only at the county level.

[Next Slide]

The old planning area scheme that we had was PG&E, SCE, San Diego, SMUD, L.A., IID, Burbank/Glendale, and Pasadena. And the ones that are revised are in green.

[Next Slide]

PG&E, we eliminated the Turlock and the Balancing Authority of Northern California, and DWR I think was added. We took out Turlock and BANC.

SCE, we added Pasadena and DWR.

SMUD, we kept SMUD the same but for planning purposes we have included SMUD within the new planning area called...

MR. FUGATE: Northern California Non-ISO. Northern California ISO.

MR. GORIN: Right. Sorry about that.

I've been fighting laryngitis so my voice is going to go in and out.

COMMISSIONER MCALLISTER: Northern California Non-ISO, is that only SMUD or is that...

MR. FUGATE: (inaudible)

MR. GORIN: And Pasadena got moved into Edison.

MR. FUGATE: (inaudible)

MR. GORIN: So essentially our old PG&E planning area becomes PG&E TAC area, and SCE planning area becomes SCE TAC area.

Northern California entities which we were just discussing not in ISO are combined with SMUD to this new NCNC planning area.

So the other planning areas are as before.

[Next Slide]

This is a table of the forecast zones within the TAC areas. So now the PG&E TAC area consists of six forecast zones where in the past it was five, which I think these six more closely resemble the ISO balance authority areas.

L.A. is still four climate zones but they're a little -- the definition is a little different than it was previously. Now it's five climate zones instead of four.

San Diego is still San Diego.

Non-CAISO Northern California is broken into SMUD, Turlock, and the rest of the BANC control area.

And L.A. is the way it was before, Coastal and Inland.

Burbank and Glendale are still there, and Imperial is there, and Valley Electric is its own planning area and forecast zone.

[Next Slide]

This is a map developed by cartography, planning areas more defined in a bigger scale. It's a little hard to see but it's a breakout of those planning areas, and these are the forecast zones.

One thing that I might mention, and somebody can correct me if I'm wrong.

For the energy consumption and sales forecast, the forecast that's for California, the geographical definition of California. But for the peak forecasts for purposes of ISO is for the ISO region which indicates that Valley Electric includes a portion of Nevada. In future forecasts, I believe, may include PacifiCorp, which is going to be a few other states outside of California, so there’s a geographical difference in definition between energy and peak forecasts.

[Next Slide]

These are the economic and demographic assumptions. The high demand case is Global Insight Optimistic. Mid case is Moody’s Baseline. Low demand case is Moody’s lower long-term growth scenario with the Department of Finance population.

Two differences from the update are the number of households and employment. I believe in the update we used household projections that were developed in-house.

MR. FUGATE: Yeah we developed them and Department of Finance.

MR. GORIN: This time we’re using Department of Finance and Moody’s household projections because they both have them available now and they are different.

[Next Slide]

So this is the new number of households

forecast. Both the revised high and mid demand forecasts are above what the low demand forecast. And this is the difference between Moody's projections of households and basically the Department of Finance projection of households.

This is from my ancient history. I believe what is going on is that Moody's is using the Census interim projections. In 2010 the Census and Department of Finance started at the same place and they have different opinions on the interim growth in interim years, and we're about half-way to 2020 and Department of Finance is projecting that we have had lower growth than the Census has and when we get to 2020 we'll figure out which one's right and make adjustments. As we did in 2010.

MR. FUGATE: Tom, just mentioned that there are two scenarios here because the Global Insight was so close to Moody's that we just classed those in one for the high and mid demand case.

MR. GORIN: Yeah, because I believe both Global Insight and Moody's both use Census projections.

[Next Slide]

This is the non-ag employment, which are all slightly higher than the 2014 update. The mid case is about a million higher.

[Next Slide]

Self-generation, Ashish is going to go into in more detail later and talk about his model. So it’s traditional electricity generation displaced by private supply used onsite such as small scale adoption and larger power plants, which are tracked in a database.

MR. GAUTAM: Yes, the large power plants report to us because of requirements. One megawatt or larger.

MR. GORIN: And the residential and commercial are developed by the predictive model, developed in-house?

MR. GAUTAM: Yeah.

MR. GORIN: We’re modeling using actual load shapes and tiered rates for IOUs, whatever those tiered rates turn out to be.

[Next Slide]

This is our new assumptions on PV energy, which are all higher than the update demand case and this is the spread in the new load, mid and high is caused by different assumptions on tiered rates and energy metering.

MR. GAUTAM: Yes, the differences between the two scenarios is driven by assumptions on PV cost. We've had lower system cost in the low demand and slightly higher in the high demand. And then we also assume that with the low demand you'll have full retail credit for exports, and then the high demand case will be something a lot lower, more like a wholesale rate and a fixed charge based on the system (inaudible).

[Next Slide]

MR. GORIN: And a similar spread for peak impacts, all higher than the 2014 forecast update.

[Next Slide]

The EV revised forecast, we used a new EV forecast, and I believe there was a workshop on that a couple of weeks ago.

Mid demand case is consistent with CARB's most likely compliance.

Low case is purely model driven.

High case assumes faster decrease in EV prices, so a greater adoption.

And the distribution of EVs was distributed to planning areas based on regression analysis and climate zones using regression analysis.

[Next Slide]

The light duty EV electricity consumption forecast is slightly lower than the previous mid demand case, I believe, about 400 gigawatt hours.

[Next Slide]

And this is our new assumption of vehicles, the spread, and I believe that was discussed in a workshop.

[Next Slide]

We also have additional electrification based on a UC Davis consultant study through Aspen. We examined shore power, truck stops, airports, forklifts, and truck refrigerator units.

The additional electrification was based on current trends and CARB legislation.

We developed high, mid, and low cases, and spent time determining what portion of that electrification was incremental to the CED revised forecast, and made splits between the TCU commercial and industrial.

[Next Slide]

These are the results in gigawatt hours. The mid case is adds about 800 gigawatt hours to the total state forecast. The high is about 1500, and the low is a little over 200.

[Next Slide]

Electricity rate cases, which will be

discussed by Lynn Marshall a little bit later with a new staff model developed using revenue requirements to allocate to rate classes to calculate average rates.

And she can discuss the high, mid, and low cases.

Currently in the mid case we’re projecting rates to increase between 10 and 20 percent to 2026.

[Next Slide]

Climate change impacts in the forecast are based on scenarios developed by Scripps. They gave us, I believe, nine cases and we took the median of those cases using -- ten? I always like odd numbers.

They’re incorporating the residential and commercial consumption forecasts using change in degree days over time.

They incorporated the peak forecast using increases in maximum temperatures by climate zone. And we have for the high and mid cases. For the low case we assume no climate change.

So we used median impacts of the two sets of scenarios we had.

Chris sent me a note last night that climate change peak impact, the maximum temperature rise of the planning areas was half a degree Fahrenheit for the mid case over the next ten years and three-quarters of a degree in the high case over the next ten years.

[Next Slide]

This is the result of climate change impacts on consumption. Mid demand is 700 gigawatt hours over the forecast period, and high demand is a little over 800.

[Next Slide]

And the increase on peak is 500 megawatts for the state and a little less than 800 on the high demand forecast.

[Next Slide]

The demand response in the forecast includes load modifying demand response. Items like permanent load shifting and TOU rates. Event-based, critical peak pricing and peak time rebates. These results are based on utility filings.

Total impact to the demand response in the revised forecast is a reduction of about 270 megawatts in 2026.

Future forecasts may include more load modifying reductions depending on PUC decisions that aren't out yet.

And there's a joint TOU analysis that's

underway that's not incorporated in the forecast as of now.

With that, I think I'm going to let Nick Fugate go over the energy efficiency part, if there are no questions on what I've presented so far.

COMMISSIONER MCALLISTER: I think we're good for now. Thanks.

MR. FUGATE: Thanks, Tom. I'm Nick Fugate. I'm with the Energy Assessments Division, formerly of the Demand Analysis Office, so I'm familiar enough with the process that the DAO goes through to incorporate efficiency into their forecasts, and removed long enough that I'm not sure I know all of the details but I'll try to get to your question, Commissioner.

[Next Slide]

So I'm going to start off, though, by reminding everyone that the forecast distinguishes additional achievable efficiency from committed efficiency. And the committed impacts are those resulting from actions that have already taken place or that are about to. A standard that has been implemented, for example, for a program that will be offered next year that has already had funding set aside and has a detailed implementation plan already in place, and we can use those to assess what the impacts would be on the baseline demand forecast. So those are committed efficiency savings.

And for CED 2015 Revised we considered some new savings measures, notably the 2016 appliance standards. Also some Federal standards that Navigant had assessed as part of their potential and goals study, but enough time has passed that those have now been from AAEE into the baseline forecast, and I'll call out one in particular.

A Federal standard on distribution transformers, which I'll talk about a little bit more in the AAEE portion of the presentation.

[Next Slide]

So when you accumulate all the savings from program standards and committed price effects, you get something that looks like this. There's very little variation in the scenarios due in part to rates and building stock and floor space operating in different directions.

For example, the high demand case has low rates so there are less price effect savings, but it also has more buildings and just more stuff, so that drives savings in the other direction.

And the opposite is true for the low demand case, so that just pushes all of the scenarios closer together.

[Next Slide]

So this depiction here assumes a counter factual in which efficiency would have persisted at 1975 levels absent any standards.

I really like the colors on this chart, it has a nice cool feeling to it.

[Next Slide]

So this is just the standards portion of the cumulative savings. These grow from about 44,000 gigawatt hours in the base here to about 80,000 by the end of the forecast period.

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So up to this point in the entire presentation we've been talking so far about the baseline forecast and all those committed savings are accounted for explicitly in baseline scenarios, but we also for this forecast have additional achievable efficiency, or AAEE, and these are scenarios that considered efforts that are reasonably likely to happen but that still have too much uncertainty surrounding their exact implementation to be incorporated explicitly in the baseline forecast.

[Next Slide]

Since AAEE is incremental to the efficiency savings considered in the baseline scenarios, the two can be combined to create a managed forecast. The next few slides describe the process that we went through to craft these AAEE scenarios.

At the high level we start with Navigant newly completed potential study. That study includes standards all the way back to 2005, so the first part of the process was we had to go and remove all the standards impacts from the potential results that we had previously incorporated in the baseline scenarios. That is all the Title 20 and Title 24 standards through 2016.

And the study also included some behavioral savings, and what we did for that is, since our base forecast is calibrated to actual demand, we took those behavioral savings projects and made them incremental (inaudible).

COMMISSIONER MCALLISTER: Is that a new, is accounting for behavioral savings new to this forecast?

MR. FUGATE: Actually, I don't remember if we did that in the last AAEE.

COMMISSIONER MCALLISTER: I don't remember us doing it.

MR. FUGATE: Yeah, they’re not very big so it could be that it was done but we didn’t talk about it. I think even now it’s not a huge amount of savings.

[Next Slide]

So initially we developed nine scenarios and presented them to DAWG and JASC, that’s the Joint Agency Steering Committee, representatives from ISO and CPC and the Energy Commission. And with their input and direction, those nine scenarios were pared down to just the five that you’re seeing here.

One scenario uses the high baseline assumptions, one uses the low baseline assumptions, and then three use the mid baseline assumptions.

When I first saw this slide, I stumbled over it a little bit. We previously used the term mid baseline, mid AAEE to describe managed forecasts, like mid baseline paired with mid AAEE. But here what I’m talking about is just the inputs that were used to develop the different AAEE scenarios, which might be made a little clearer here.

[Next Slide]

So here are basically all of the categories of assumptions that were wrapped up into those five scenarios, inputs like building stock and retail prices are made to be consistent with one of the baseline demand scenarios. And that first row in red describes which baseline scenario we're talking about in each column.

On top of that the savings scenario is allow to vary, and that's the second blue row there, and it has more to do with what the efficiency landscape might look like over the next decision. For example, how many Title 24 updates might we expect to see, so the high savings scenario has more standards updates.

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So those five scenarios were presented to DAWG, the Demand Analysis Working Group, and they pointed out that the peak savings seemed unusually high relative to the energy savings.

[Next Slide]

We looked into that and found two causes. The first being that Federal distribution transformer standards that I mentioned earlier which had a very high peak to energy ratio. And I think I had a note on that, it was something like 200 megawatts to -- so savings from the distribution transformer standards amounted to around 250 gigawatt hours for energy and 200 megawatts for peak, so that's a pretty high peak to energy ratio.

So we looked a little more closely at that standard and found that it was already in place, so we pulled that out of the AAEE and incorporated it into the baseline scenarios through adjustments to line losses.

COMMISSIONER MCALLISTER: Nick, did you figure out whether that characterization of high capacity savings to energy was real or not? It could be depending on where the savings of the transformers are coming from, right?

MR. FUGATE: Yeah. I mean, intuitively it makes sense that the transformer standard is going to have a higher peak.

COMMISSIONER MCALLISTER: Yeah, if efficiency is coming less from the core and more from the windings, then you've got high capacity savings, right?

MR. FUGATE: Right, yes. But I don't know, I mean, line losses is a difficult thing to get a good handle on, so I won't comment on real or not real.

COMMISSIONER MCALLISTER: But you then incorporated the capacity and the energy savings back into the baseline forecast.

MR. FUGATE: Yes. So what Navigant had identified as savings we took out of AAEE and incorporated it as line losses in the baseline, as an adjustment to line losses in the baseline forecast.

The second cause had to do with an uncertainty adjustment that Navigant’s model was using to apply to codes and standards. This savings adjustment was informed by the 2006 to 2008 EM&V study and that adjustment penalized peak savings more than energy. This adjustment was removed in Navigant’s more recent, the 2015 potential study, in response to the 2010 to 2012 EM&V which indicated better performance from codes and standards. So removing that penalty caused peak savings to increase more than energy savings, so that also pushed up the peak to energy ratio of the AAEE.

And our compromise to that was to reinsert the uncertainty adjustment but at 50 percent of its original level. So we had one EM&V study that said there should be an adjustment to codes and standards. We had another study that said, well, maybe not, so we split the difference.

COMMISSIONER MCALLISTER: So you still are debating codes and standards to some extent but just not as you’d like.

[Next Slide]

MR. FUGATE: Right. This is basically what I just said, our response to the two causes of the high peak to energy ratios in the AAEE scenarios.

So here are the peak results from the five scenarios. This chart you can see the five scenarios, and in 2025 there's two points that are shown for reference, that's the mid and the low savings scenario from the 2014 update.

You can see all five scenarios are significantly lower than the mid-mid case from the 2014 update, and this is due to some of the points I mentioned already, particularly that some of the standards were moved out of AAEE and into the baseline forecast.

Also, realization rates were lessened in light of the 2010 to 2012 EM&V study.

[Next Slide]

Here's the results for energy savings, a very similar picture.

I'll point out that the low baseline savings scenario is very close to the mid baseline high savings scenario and it's the same thing on the other end with the low cases. And again, this is because we have marrying the baseline assumptions with regard to rates and floor space acting in different directions and pushing those together.

[Next Slide]

So new to this forecast we have AAEE estimates for the POUs, at least for LADWP and SMUD. So these are the two largest POUs and covered a lot of ground. At this time the only POU for which we have a potential study detailed enough to process into AAEE estimates, so that's partly why we started with just those two.

Their potential studies did not have program savings scenarios nor did they have results for codes and standards, so I believe what we did was, I believe Navigant developed codes and standards estimates for these two utilities using the same approach that they did for the IOUs, so we do end up having scenarios for the POU AAEE but the difference in those scenarios is based only on codes and standards.

[Next Slide]

So here are the results for peak impacts for LADWP and SMUD combined. You can see a distinct change in growth in 2020, and this is because LADWP's potential study went out just five years at the level of detail that we needed. So after 2020 LADWP savings level is held constant.

[Next Slide]

And energy savings.

[Next Slide]

So I’m going to finish off with a comparison of the mid baseline peak demand forecast with one managed by the mid savings AAEE scenario. Our baseline has a pretty low growth rate to begin with, and clearly the inclusion of AAEE pushes that growth rate negative.

[Next Slide]

And here’s the same comparison for sales, electricity sales.

[Next Slide]

So next steps, not just for AAEE but in general. Comments are due, I think December 31st, right? Okay.

Most major revisions occur between the preliminary and revised forecast, so any changes that happen between now and the adoption should be relatively minor.

Our Commissioners will make a decision on which combination of baseline and AAEE should be used for the state’s planning purposes.

And then the forecast adoption is scheduled to happen at a January business meeting.

[Next Slide]

So with that, I'll pause and ask if there are questions or comments?

COMMISSIONER MCALLISTER: Let's see. So I'm going to sort through here and keep looking at it and probably come back with a few questions that I might not be thinking of right now.

But one question I have, or one comment, I guess. So we now have the adopted AB758 action plan, and we have SB350 and we have some statements of policy goals. And I guess this is analogous to the conversation we've already had a couple of times with the transportation forecast, so we have these goals, you know.

So the modeling is the modeling and you've got the leverage you've got to track up that way and predict what you think is going to happen with what you know.

There's also this goal that is a separate number that's, okay, here's our goal. And I guess it'd be good in the case of 350 and the Governor's efficiency goal, in 2030 there's a we want a doubling of savings, and we can translate that into a number and it could well be transposed on these graphs we extend out the years a few years.

For 758 we've also got a graphic in the

action plan that's now adopted that says here's what a doubling means to us in terms of energy efficiency savings in most of our existing building stock.

So it would be helpful, I think, to have like a dot for those goals. Maybe a line but even just a dot like by this year we want to be here, and put it on some of the outputs of the modeling to get just a basic sense of, okay, given what we know, what we're doing now, what we think is going to happen, are we going to get close to our goal, is there a gap? And that gives us some information about what we need to do on the policy front.

CHAIR WEISENMILLER: Yeah, I would discourage you from going too far in that direction. I mean, It's really what we have to do next year is figure out how to do that.

COMMISSIONER MCALLISTER: Yeah, yeah.

CHAIR WEISENMILLER: I think at this point I don't want to give anyone any delusions, but we incorporated the goals into this analysis. But at the same time we take the goals very seriously.

COMMISSIONER MCALLISTER: Maybe it's not to publish it in the actual forecast or in the IEPR this year, but certainly as a policy matter we need to know that so we can plan going forward.

CHAIR WEISENMILLER: No, I think the IEPR itself, the document has to reflect this is what's been adopted, this is the timelines, this is what we're going to do.

COMMISSIONER MCALLISTER: Yeah.

CHAIR WEISENMILLER: The question is how much, you know. And part of our messaging has to be we really need to figure out how to build that in the forecast throughout next year, and certainly we want to keep people involved in that.

But as I said, I'm not quite sure at this point if it's baked enough to put into this document, or at least be in the graphs as opposed to the text.

COMMISSIONER MCALLISTER: Yeah, well we're certainly gonna get a few comments along those lines. If we don't do it then we're going to get comments calling us out and we need to explain that this is what we're going to do moving forward next year and the year after.

CHAIR WEISENMILLER: Yeah, exactly.

COMMISSIONER MCALLISTER: But those numbers do matter and I just want to make sure that we tee up the discussion for next year and the execution in the year after that to let the world know, well, we do have these goals, we know we have these goals, and we need to inform our policy direction and our policy actions going forward to meet those goals, and that is going to be reflected in future forecasts.

CHAIR WEISENMILLER: That I agree. I think when the drafts came out people were in the mode of have you incorporated it, and it was like, oh yeah, and it's going to take awhile.

COMMISSIONER MCALLISTER: I mean, I see this as part of the incorporation, so yeah.

Thanks a lot, Nick.

MS. RAITT: Thanks Tom and Nick, really appreciate you filling in today.

So next is Ashish Gautam.

CHAIR WEISENMILLER: We want to make sure we thank Tom for filling in, and Nick both, as Tom leaves.

MR. GORIN: I'm not ready to leave yet.

MR. GAUTAM: Good morning, everyone. My name is Ashish Gautam and I'll be going over the self-generation forecast.

This self-generation forecast had a lot of moving pieces because we had so many key decisions come out this week really, and so we were not able to address them adequately.

I'm going to talk quickly about the

different data sources we used to track DG activity, and then I'll go over some of the changes we made relative to the prior forecast, and then I'll be going over the statewide results. The results for the individual planning areas will be provided later in the afternoon. And then I'll give a quick update on some of our next steps and take questions from the audience.

[Next Slide]

Historically, we've always relied on rebate program data, which has been a useful way for us to track what's going on in PV adoption and even in non-PV adoption. But it came to our attention that rebate programs go away and there's still a great interest in installing DG. The rebate programs become less reliable.

And so for this IEPR we issued a data request to the utilities asking for PV interconnection data for 2012 and 2014 by month and customer sectors.

We also had a more geographic (inaudible) requested it by zip code, so that helped us look at trends even more.

[Next Slide]

The PUC has started to publish their

interconnection data online, so we expect going forward that we're going to make greater use of that dataset so it's going to become a regular source for us to work with.

There's still an issue about POUs. They report on a different schedule to our renewables office but it's still something we could make good use of.

[Next Slide]

Some of the changes that we made relative to the last adopted forecast.

We've updated our PV production shapes. This is something we received from the PUC. They had hired a consultant to do some EM&V valuation of the CSI programs, so they provided that dataset to us.

We've also updated our peak factors to translate installed capacity to impact during system peak.

Again, this is an adjustment that we're making based on what we know today as more behind the meter PV is installed, peak hour is going to shift and we suddenly are going to need to think about how that peak impacts on the change over time.

We tried to look at that for the revised forecast but ultimately we concluded that we need to update our existing low shape database, so that's a project. I'll talk a little bit about that later on.

Another update we have is we're using install cost data from the PUC public tool that they developed as part of the NEM 2.0 proceeding.

Again, we're updated our residential sector model to use actual retail rates instead of average sector rates. It's a step in the right direction but it adds even more uncertainty because even with the tier flattening there's a call to go to time-of-use rates. That's something we haven't really looked at in this forecast.

[Next Slide]

Some additional updates we made relative to the July forecast we released, the preliminary forecast.

We're using the decision on the residential rate redesign that collapses the tiers from four tiers to two tiers with a super user charge and there's a monthly bill.

We've added scenarios to the PV costs to vary by demand scenario. So this gives us more separation between the scenarios.

While we were preparing the revised forecast, the PUC had not ruled on the NEM decision, so we assumed that in the low case there will be a full retail credit for exports, and that in the high case the exports will be compensated at a much lower rate and there will be a capacity charge, a fixed charge based on the system size. So the low and the high cases act like a bookend between what would be more favorable for the solar industry and what's sought by the utilities.

In the mid case we averaged the additions between the low and the mid.

Tuesday the PUC has released a proposed decision where the retail credit is going to -- system owners are still going to get a retail credit for their exports, and there's a call for new NEM customers to move on automatically onto a time-of-use rate by 2019.

And there's also I believe for the first time a charge for interconnection. And customers would also be required to have monthly netting and start paying for certain nonbypassable charges.

So those are things we were not able to look into for this revised forecast.

A first for us in this revised forecast is a preliminary look at energy storage, and I'll go over that a little bit later.

[Next Slide]

We did not do many changes to the fundamental way we forecast. DG adoption is still based on payback adoption. Again, the payback is based on factoring the possible costs and benefits to a system owner. And the payback is applied to a diffusion curve to model the additions.

Again, we're going to have different results by the scenarios because of inputs that differ by scenario.

[Next Slide]

The first result is the non PV impacts. In 2014 we estimated the non PV impact was 13,000 gigawatt hours and would grow to just under 16,000 gigawatt hours. All three cases are very close to one another, and has to do with offsetting effects embedded in the demand scenarios.

The growth rates are about similar to the prior forecast, just have a higher starting point.

We have an increase in the 2014/2015 period because there was a change to the PUC rebate program for (inaudible) projections. They've been allowed to participate in the program so that bumps up the starting years, but otherwise the growth is expected to be roughly the same relative to the last forecast.

[Next Slide]

Next we have the peak impacts.

Again, all three cases are very similar to one another but the three scenarios are substantially higher than the last forecast, and the primary reason is that we're accounting for the energy storage impacts here, and we did not consider storage in the last forecast, so that's why we have a higher peak impact.

If we remove the storage then the cogen impact is only about 100 megawatts higher so that would be much closer.

[Next Slide]

So next is the statewide PV impact.

Relative to the last forecast, all three scenarios are substantially above the last forecast. As you can see, we have much greater separation among the scenarios. Again, the low demand case assumes more reduction in system costs and that there will be retail credit for exports from them.

The high demand case has lower decline in system costs for PV but we assume that system owners are not going to get compensated at the retail rate.

And the mid is the average of the additions between the two cases.

So energy impact ranges between 13,000 gigawatt hours to 30,000 gigawatt hours, representing 4 to 10 percent of consumption. We expect slower growth up to 2016 due to the expiration of the tax credit.

There's a potential for a kind of compromise to be reached in extending the tax credit so that will have an impact, but we were not able to look into that for this revised forecast.

Growth is primarily led by the residential sector. We still have quite a bit of increase in the non-residential sector relative to the 2014 forecast, but again, the residential sector dominates.

Annual growth rates here range from 9 to 17 percent a year, so there's an aggressive forecast, but relative to some of the announcement from the utilities posting their progress to meeting the net metering cap, this forecast, at least in the near term, may be a little conservative. At least we don't expect the utilities to reach the net minimum capacity limit until 2018, 2020 timeframe, but there's already an expectation that San Diego may reach their limit as early as next year. So there's that.

[Next Slide]

And this is the peak impact from PV. Estimated the impact to be about 1100 megawatts in 2014, and then to grow to 2900 megawatts to 6400 megawatts by 2026.

The installed capacity ranges between just under 8,000 megawatts to under 18,000 megawatts by 2026.

As I mentioned earlier, we're still assuming that the peak factors represent a later evening peak and we're not looking at the shift, but that's going to become more important and hopefully once we have an updated load shape data we can start to incorporate that.

[Next Slide]

So this is our first cut at storage. There's the energy storage roadmap that has a goal of 200 megawatts of insulation behind the meter.

If you look at the self-generation rebate program, about 70 percent of that goal could be met by 2016. And that leaves the question of what do you do about the next ten years. We just assume that the average what's pending through that rebate program will continue on.

We've learned our lesson from DVs and forecasting that so we want to try to not do too much in storage.

One of the issues historically is that we don’t have a good handle on operational data like we do for photovoltaics. This is where we were close to the PUC staff and they were very helpful in getting us information on storage capacity and peak impacts.

Another takeaway here is that 70 percent of the storage projections we estimate to be in Edison’s territory. That’s just what’s reflected in the rebate program. And I think the non-residential sector accounted for about 60 percent of that. Again, that just reflects what’s going through the rebate program.

[Next Slide]

Uncertainties. I mentioned earlier about rate reform. We’ve incorporated the tier flattening, but again there’s the issue of time-of-use rates and also how the time-of-use periods may be defined.

There’s the NEM reform. We’re unable to account for that, but hopefully in the next update we will.

There’s also the cost and technologies and what kind of improvements we can see in the modules and whatnot, converters especially.

This last bullet here about aggregating DG is something that’s noticed and paid attention to but we’re not too familiar on how this thing may play out. We’re aware that in the distribution resource planning there are proposals for third party vendors to aggregate the output of different technologies and offer good services. So we’re going to be probably looking at both supply and demand side maybe later, but it’s just not real clear how this is going to play out but it’s something we’re aware of.

COMMISSIONER MCALLISTER: It seems like the assumption on storage particularly the assumptions are pretty key in terms of especially, if it’s behind the meter, if it’s up to the entity, you know, up to the customer figure out how to reflect storage, and that’s (inaudible) will impact the peak.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: You know, so I guess building up that model to reflect operational characteristics as they exist in the world as we learn more about them and that seems pretty important.

CHAIR WEISENMILLER: Actually, you’ve done quite a bit here, looking at the summary. I think the good news is that you’ve got some time to -- you don’t reflect everything last minute, but you’re never going to, and some of it has gone different directions although most of it's on the upside at this stage. But I think you've got a lot of work cut out over the next couple years.

One of the things to avoid, though, is the (inaudible) effect. Some of the more interesting technologies which we're certainly struggling with more trying to move more toward an IRP are things that are combination.

As you know, Susan Kennedy has this program in southern California which could be either demand response or storage. So I don't know which bucket you're putting it into in that fashion but the answer is that as people, and certainly the preferred (inaudible) and now with the ISO doing the preferred step there, although the ball's now in the PUC's court and it's complicated, is that again as we go forward is to be looking much more at combinations and making sure that we're neither double counting or undercounting.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: A lot of creativity is coming and certainly continue to challenge you to capture all the creativity.

COMMISSIONER MCALLISTER: Yeah, this is

great because you have time because the numbers are still pretty small here so it's not like a huge, it's gonna be a huge swing in the way of (inaudible) forecast but we could prep the ground for the future.

[Next Slide]

MR. GAUTAM: Just quickly our next steps.

We'll try to update for the 2015 interconnections, and we'll leave out what we want to make on net metering and the possible extension to the tax credit. It's just something up there.

Longer term we're looking to update how our peak demand model works. We have a contract out there for updating our load shapes. It's going through the procurement process, so hopefully we'll start work within a month or so.

There's also rulemaking proceedings going to modernize our data collection activities, and we're trying to see where the DG part can tie in, but that's just something that's out there.

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

COMMISSIONER MCALLISTER: Thanks a lot. Of course, on net metering we have the proposed decision, we don't have the adopted decision, so at some point you just have to wait until we go to the big update next.

MS. RAITT: Thank you, Asish. Next is Lynn Marshall.

MS. MARSHALL: Hello, I'm Lynn Marshall with the Energy Assessments Division, so I'm discussing the revised retail electricity rates that are input in the demand forecast model.

So to be specific, these are annual average electricity rates that go into the sector forecasts of annual energy consumption. So by their structure, those models are currently set up to capture any time-of-use impacts so that's something that we'll be discussing later separately.

[Next Slide]

So since the preliminary forecast developed earlier this year, much of the data sections have been revised, so the models now incorporate in revised natural gas price outlook that was discussed and forecast here last month.

It incorporates the July 2015 sales and demand forecast.

And then we incorporated a lot of utility specific information from the data that the larger utilities submit on their IEPR supply and demand forms. So from their supply forms that includes projections of their energy and capacity portfolio mix, including specific information on resource, utility resources, time growth, their renewable portfolio.

Then from the revenue requirements information they submit on the demand forecasts they were using selected information from that, including information on their specific cost for things like hydro resources, nuclear, coal, and long-term broadcasts they may have their costs for their renewable resources currently under contract, and then other elements of revenue requirements such as their transmission distribution costs, customer service costs, public programs they are funding, debt services, etcetera.

They also provided information on cost allocation factors.

[Next Slide]

So also for the revised forecast we developed some high, medium, and low case projections of the distribution element of revenue requirements.

So for the investor-owned utilities, in their general rate cases they have specific data on capital expenditures and you could classify those by categories like customer growth, load growth, and then there's a bunch of other stuff ongoing replacement.

So like adaptive methodologies that are used in the Phase 2 general rate case to allocate marginal costs, and use those to extend the projected capital expenditures for the load growth and customer growth beyond the current GRC period.

For the other elements of cap ex and for public utilities didn't have as much detailed information, I used escalation factors comparable to what was used for the 2013 IEPR varying from about 2 percent to 4 or 4-1/2 percent.

Then we also updated the transmission outlooks, starting with the CAISO model projected transmission rates, updated that and extended it beyond 2020 making some reasonable assumptions about likely additions.

And then we've also reviewed for the short end of the forecast reviewed general rate cases, public utility rate actions, and factored those in.

And then finally we got some informal comments from CPUC Energy Division staff and we also presented the revised forecast to a DAWG subgroup and got some useful feedback there.

So just to recap the scenarios in the

context of the rate case scenarios, we have high demand and low gas prices, low carbon prices, low cap ex because we have less penetration of distributed resources.

And then in the low energy demand case we have higher rates, high gas prices, high carbon prices, more cap ex.

[Next Slide]

So these are the natural gas price cases we're using. They were presented at a natural gas outlook workshop last month.

So the mid case is now using a blend of forward prices for the short end of the forecast out to about 2019, and then moving to our staff NAMGAS model projections for the rest of the forecast.

So it's a more gradual transition, but still even in the mid case so that given where we are that's still about an 80 percent increase in the price by 2019.

In the high case we're doubling the gas price by 2020, so that's going to have a pretty significant impact on the results for utilities with a lot of reliance on gas.

[Next Slide]

And then just comparing the mid cases going back to the 2013 IEPR, the longer forecast is the same in the mid case, but we're coming at it from a lower starting point than in the 2013 IEPR, so bigger percentage increase in the short end.

[Next Slide]

So these are carbon price scenarios. These haven't changed since the preliminary forecast but since they do have a significant impact, particularly on the high case, I wanted to point that out. So down here on the left hand you have prices for metric tons of cargon, and on the right axis is an estimate of the price per megawatts hour. So we're down around $13 per ton and $6 per megawatt hour.

In the low demand high price case, that gets to like $27 per megawatts hour by the end of the forecast, so that's a big factor in the price results.

CHAIR WEISENMILLER: I was going to note that our cap and trade numbers were never close to this, or pretty much as before.

MS. MARSHALL: They are, and that's exactly why I wanted to point this out.

So the low demand high price case is by no means symmetric either in impact or in probability. You'll see that in the results. Yes, we're nowhere near there.

And I think probably Air Resources Board is in the process of addressing the Phase 2 rules, and I think based on that analysis would suggest that we would have a lower high price scenario in the next round.

[Next Slide]

So translating the gas and carbon price, this shows the wholesale market price of electricity cases using a heat rate curve methodology. It also shows the price for new renewable purchases that I'm using.

So this was developed from mid case levelized costs and our costs of generation report and took an average based on the resource mix that was being added in our flex (inaudible) results.

I would say given where the price of solar is going, this is probably high, so updating this would probably have a steeper drop in this curve.

But still you will notice that in the high price case at about 2020, renewables are cheaper than conventional power, so you would expect in the model we have utilities purchasing up to their stated renewable portfolio standard; well in reality you'd expect them to be going beyond that target just based on economics but that’s not captured in the model. So again, another reason why the low demand high price case is somewhat overstated.

[Next Slide]

So this is a snapshot of the statewide weighted average results compared to the last couple of cycles. So we’re ending up, we’ve got commercial sector less than 1 percent growth, or 0.7 percent. Slightly lower than the previous couple of forecasts.

And one of the things compared to the 2013 IEPR, it’s using a different model. It’s using more utility specific information, and so in the RPS calculator we were using before it wasn’t really characterizing some of the public utilities practice, so we see when we go to that individual utility results overprojecting those utilities in particular.

So this is commercial annual average growth rate, 0.7 percent.

[Next Slide]

Residential, a little closer to 1 percent. And generally among most but not all utilities there’s a trend for more costs as utilities look at their cost of service, that is more driven by residential sector than non-residential, so those rates tend to go up a little higher.

There are some utilities where that’s not the case, so that translates into (inaudible).

[Next Slide]

So going a little more in-depth, these are big five utilities in the residential sector for the mid case. Most of the utilities we have growth around 1 percent. There are several exceptions in the LADWP paper which I will talk about more.

I guess you can characterize there’s utilities that are well on their way to accommodating RPS, modernizing their infrastructure, and some utilities that are just starting, and those are the utilities that have the higher growth rate in the forecast area.

[Next Slide]

The commercial sector again tends to be lower growth rate so that the commercial sectors I’ve used utility costs, changes in cost allocation factors where they were available.

[Next Slide]

Those are the industrial cases.

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Okay, now I’m going to go through each of the planning areas. I’m showing the conventional, the old planning areas. Easier for comparison purposes. I actually generated the rates both ways by using a different weighted average.

So Burbank and Glendale, those two utilities are in somewhat different positions. Burbank actually has a little advantage, they have more urban and commercial case. They have been able to keep their rate increases at around 2, 2.5 percent.

Glendale, on the other hand, found itself in 2013 negative cash flow funding, cap ex, and operations out of reserves, negative (inaudible), and badly needing to modernize their grid, clean up some of their generation resources and facilitate a bond issue.

So they have now implemented a pretty significant five year rate increase that factors into that mid case. After that it levels off.

[Next Slide]

IID, another utility that for along with no increase to their base rate for many years. In fact, you can see the rate residential customers were paying actually declined.

So they recently passed a pretty significant rate increase to, they've got a whole transformation issue, renewable portfolio standards, FERC imposed costs. So they're just coming to grips with dealing with a lot of the new requirements now.

[Next Slide]

LADWP, you may have heard, has some significant issues to deal with. So they have proposed -- this forecast factors in their proposed rate action for the next five years. About 75 percent is to fund what they call power supply transformation, so that's dealing with their coal. That's complying with the RPS standards. There's a significant energy efficiency program, so local solar programs. And then also they have a significant agent infrastructure problem, so that's part of the work that would be funded through this rate action.

I was expecting or hoping that I would say they just voted to approve it at the L.A. City Council yesterday. They didn't; they voted their water rate increase, but it might get approved. It'll come back to the Board in January.

Now, as part of that rate action they did some extensive scenarios on sensitivities. Some of their sensitivities actually pair nicely with our scenarios. So I used their sensitivities for the first five years and then blended it with the staff high/low cases.

[Next Slide]

So Pasadena, which is now part of our Edison forecast, they've also implemented, I think the first year of their rate increase is something like 8 percent followed by 2 percent.

So again, this is a utility that has really had pretty stable rates and they're just looking at the expenditures they have to meet. They have a 40 percent RPS goal, a lot of aging infrastructure, and not a lot of demand growth in some of these, especially the southern California utilities, Burbank, Glendale, Pasadena.

So these are significant rate increases but you wouldn't project past the next ten years the same rate of increase necessarily.

[Next Slide]

PG&E. Here we have a relatively low growth rate, 8 percent annually. They've already in the recent years implemented some pretty significant rate increases, so a lot of the (inaudible) before some of the other utilities are in terms of some good investment, RPS compliance, etcetera.

Shortly before I completed this forecast their 2017 GRC rate case proposal came out, so I incorporated some estimate of impact from that, in particular their capital expenditures, but some of those numbers will no doubt change.

[Next Slide]

And then Edison, you can see the low demand high case is quite a bit higher here. A good chunk of that is the impact of gas prices, the high gas, natural gas prices. PG&E's got a little more hydro, they've still got nuclear so they don't have quite the response there.

And then also their 2015 GRC was still pending, so there was some more uncertainty as to the trend of capital expenditures in that position so they'll have a wider range on those cases.

And also I think generally in their distributed resource plan they have a more possible upside on capital expenditures to support distributed resources.

[Next Slide]

San Diego, another utility that's very sensitive to natural gas prices. No hydro, no more nuclear. It levels off. They've got some costs going away that mitigates that somewhat.

And again, so this includes the first few years from their most recent general rate case.

[Next Slide]

SMUD now has another less than 1 percent growth rate. I think their management would say the lower rate forecast and the high demand case is more in line with their projections, 2, 2.5 percent rate increases is generally what they stick to.

They seem to do more than other utilities forward procurement of natural gas, it keeps their costs very stable and rate stabilization capped.

And then adding SMUD with the other non-ISO northern California utilities, the trends are generally the same. Rates are slightly higher so there’s utilities like Modesto Irrigation District that actually have higher residential rates. They probably have some overallocation of cost to residential down there, actually.

[Next Slide]

So those are my results. Do you have any questions?

CHAIR WEISENMILLER: I was just going to make the observation that one of the changes that (inaudible) are doing are basically looking at the depreciation rates.

MS. MARSHALL: Yes.

CHAIR WEISENMILLER: If you look at the most recent GRCs, the amounts have really been adjusted by leveling depreciation.

MS. MARSHALL: Yes. So I was focused on forecasting (inaudible) and did okay on that, and then some other elements are taken. So you're right, that is something to watch in the future.

Any more questions?

COMMISSIONER MCALLISTER: No, I think I'm good. Thanks a lot.

MS. RAITT: Thanks, Lynn. So with that, I think we can go ahead and break for lunch. So we'll break for lunch and come back at one.

COMMISSIONER MCALLISTER: Yeah, one o'clock.

(Lunch Recess)

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AFTERNOON SESSION

MS. RAITT: Okay. Welcome back to the Revised Electricity Demand Forecast, and we have Sylvia Bender to speak for this afternoon.

MS. BENDER: Okay. Let me get started. Can everyone in the room hear me? Let’s check on that first.

This afternoon I’m going to give a summary of some work that the three agencies, the Energy Commission, the Public Utilities Commission and the Independent System Operators, have done to look at time-of-use analysis. This is a time-of-use analysis for time-of-use rights.

One of the things I want to do, first of all, is recognize the fact that I have two joint authors in this staff report, Tom Doughty from ISO and Simon Baker from the Public Utilities Commission. Neither of them could be here today, but I do have able help from Bob Everett and Delphine Ho from the ISO and Bob Levin from the Public Utilities Commission, so I will be turning to them for technical questions that I’m not going to be able to answer.

[Next Slide]

Time-of-use rates have been used in

California as a load-modifying demand response, and are a preferred energy resource.

To date, residential time-of-use rates have been complex and enrollments have been very low and static. However, that process is about to change with some recent CPUC decisions that could lead to the default time-of-use enrollment in 2019.

What we are doing here, we are looking at, as you've already heard this morning, there is some amount of demand response, non-event based demand response in the forecast already. But what we wanted to do in this supplemental analysis is look at how that picture might be changing and what those potential impacts might be.

[Next Slide]

So the goals of this joint analysis are really to look at three particular areas here.

Look at residential fixed charges and time-of-use adoption rates.

To look at time-of-use periods for residential and nonresidential rate classes.

And to look at the transition to mandatory and default critical peak pricing for small nonresidential customers.

We're doing this analysis under our joint agency steering committee, which is made up of representatives from each of the three agencies. We're examining the potential of these new impacts.

We are not incorporating any of this into the 2015 IEPR forecast. I want to be very clear about this. This is all supplemental to the forecast. So we're looking ahead at what the situation might look like in the future.

[Next Slide]

So to do this we set up a work plan and we have developed six scenarios in all. These scenarios have been developed through an interactive process among the agencies, reviewed through the demand analysis workgroup and through several webinars. So we feel that we've gotten a pretty good cross section of input into these six scenarios.

Four of them consist of rates that are already adopted or proposed looking at based on the current proceedings.

Two of them are more experimental scenarios where we're looking at advanced rate designs, looking specifically on how we might mitigate grid conditions under circumstances of high renewable penetration.

So here we're looking at two different components in order to do this.

The first component is tiering periods that were developed by the ISO for four different seasons, so from winter, spring, outer summer, inner summer.

And then the CPUC contributing their staff designed conceptual rates that include a fixed customer charge. And here I wanted to stress that these are conceptual hypothetical rates that are based on nothing that is in any proceedings anywhere.

We're going to look at these scenarios in a little more detail in the next slide so I won't go into too much detail here.

One of the things I want to mention also is that we have two independent consultant analyses of these scenarios. The two reports, one by Christensen on the Scenarios 1 through 4, and then one by MRW on the all residential scenarios across the six scenarios. Those are all going to be docketed in this proceeding. They are going to be fully available with their data for everyone to see. What we have done here is also provide a staff summary of those two reports.

One of the things MRW did was provide a very detailed literature review looking for studies published basically since 2006 that would be relevant to California, that would include some quantitative results that we could use to frame the scenarios.

They looked at 48 different studies and found 33 of them relevant enough to summarize in their report, so it's a very good resource for finding a good analysis of these kinds of studies.

What they learned from the studies is that the time-of-use periods are usually very broad, six to eight hours, typically summer afternoons and early evenings.

Most of the programs have been customer opt in, very few with default rates.

Most of them have studied both with and without enabling devices.

Summer peak is the area that receives all the attention, not so much the other seasons.

None of them studied whether load shifting occurred at the end of any peak period.

And none of them considered three different time-of-use rates.

The study that actually turned out to be the most useful for these analyses was one that actually was a little bit older than the timeframe they had established. It was a statewide pricing pilot from 2003 and 4. It's really the only comprehensive study that looks at California and includes elasticity input and it quantifies demand response by climate zone.

So those are some of the constraints we were working under here.

[Next Slide]

So this is the map of the scenarios that we have. Again, as a method to test, we added the fixed charge across in each one of them, and you can see here for the baseline results we have participation rates now that are very low at about 2 percent. We vary these across, ramping them up to 10 percent, 30 percent, and to 80 percent in some of the default scenarios.

And then again there’s a set of price periods in Scenarios 1 through 4 that are basically built off proposals that IOUs have already made.

And then Scenarios 5 and 6 where we’ll talk a little bit more about how we got to the ISO recommended time periods and the CPUC conceptual rates.

So this is the framework under which we’re working.

[Next Slide]

The ISO had a series of operational questions that they began their analysis with, most of which again are related to grid conditions. And these questions are essentially representative of those issues.

Their analysis began with historical data from 2013 and 2014 looking for identified trends in renewable generation compared to electricity demand on the system.

So the data that they gathered also came from the CPUC's (inaudible) proceedings, 2021 wind and solar projections, as well as our demand forecast results for 2021 and 2024.

From all of this the ISO created projections of future load curves in the year 2021. They anticipated electricity needs and net load curves calculated by subtracting the solar and wind output from the overall, then they created time blocks comparing the loads to find net distributions.

[Next Slide]

Some of the results of that particular work.

The coincident peak demand in the ISO varies by season and is generally coincident with the ISO during spring, fall, and winter, but it's one hour ahead of PG&E during the summer.

However, significant renewable penetration, especially from solar, shifts the summer coincident net load peak later in the day, from 4:00 to 5:00 p.m. to 6:00 to 7:00 p.m.

The ISO's data also observed that demand was particularly high during summer weekdays in July and August, essentially creating super peaks.

On the other hand, plentiful renewable resources also mean that energy production can outpace demand, especially during certain times of day.

And the absence of storage capabilities that are significant at this point, the surplus energy may be curtailed.

So the tier view design is a potential solution to manage the impacts of these renewable resources.

[Next Slide]

So now I'm going to show you a couple of graphics that came out of this.

This is the weekday conditions that were graphed. The colored bars represent 95 percent of the load distribution in each hour. The top and bottom lines are the maximum and minimum net loads in each hour. Blue is 2014. Red is 2021.

The minimum net load reflects the level of generation required for liability and may result in negative wholesale prices during midday from 10:00 to 4:00, which you see highlighted there.

So these surplus conditions expected during what we’re going to call the super peak hours are 10:00 to 4:00 in March and April weekdays. Weather is mild, air conditioner use is at a minimum.

Additionally, supply is projected to be very plentiful starting at 9:00 p.m. and then again through the next morning.

[Next Slide]

On weekends you see a relatively similar distribution, with the exception of July and August. Again, supply surplus is expected to occur during these hours from 10:00 to 4:00 when solar generation is at its highest.

[Next Slide]

These patterns resulted in recommended price patterns for weekends and weekdays that will be reflected in what we’ll from the CPUC conceptual rates that we used for Scenarios 5 and 6.

And these periods again were developed by the ISO to match future grid conditions, reflecting these renewable penetration rates.

And the one thing that’s a departure from most TOU rates is that these rates and these periods are designed to encourage rate reductions. Scenarios 5 and 6 specifically were designed to explore the possibility of incenting customers to shift their consumption away from peak periods when generation is plentiful.

[Next Slide]

This is a map of the weekdays and these different time periods. Three time blocks per day tailored to the seasons and the higher use patterns on weekdays versus weekends. So these periods reflect system needs when generation is constrained during the late afternoon/early evening peak and plentiful at midday. The time periods, again, designed to reduce peak load or shift that demand to non-peak periods.

[Next Slide]

So now that we have the time periods established, we need some conceptual rates to go with them, so this is the CPUC component of this. Bob Levin is actually the person who designed these rates for us, so any technical questions I'll defer them to Bob and Bob can explain this in more detail to any of you afterwards.

Essentially, he used a two-step process, using first of all the economic principles to model this, building it up from rate components, a so-called science of rate design.

And then secondly, putting a cap on some of these rates to make then potentially acceptable to customers. Some of them looked, you know, trying to keep the super off-peak rates as low as possible, and keeping the super peak rates capped to, again, make them acceptable to customers.

[Next Slide]

So here's what those particular rates look like. They range from maybe up to 60 cents in the highest period here.

So the conceptual Scenario 5 and 6 TOU rates are designed to be revenue neutral, designed to explore the potential for price response. But again, reminding you that these are not proposed by any utility or contemplated by the CPUC at this point. Strictly for supplemental analysis.

And the example you see here is for PG&E. In the full papers you'll see them for all of the three (inaudible)large utilities.

Let me define for you what these particular periods are that we've got here.

So for inner summer, those months would be July and August. Outer summer we would consider

May/June, September/ October. Winter would be November, December, January, and February. Spring, March and April.

[Next Slide]

And this is the same example again for PG&E looking at the weekend rates in those same time periods.

[Next Slide]

So what did our consultants show us in terms of results from all of this.

This is a combination of the two consultant reports, the Christensen report and the MRW report. Shows the combined peak hour load reductions for all three utilities under Scenarios 1 through 4.

The results between the studies are very consistent, and they show that an increase in the default participation percentage, which went from 10 percent to 30 percent, triples the amount of load reduction to approximately 250 megawatts by 2025.

If we add targeted marketing or enabling technology, we could take these down perhaps another 60 megawatts.

Scenario 4 was one that was only analyzed by MRW. That one shows that load reduction can more than double to 650 megawatts if we go from a 30 percent opt-in percentage to an 80 percent default. So there's a very significant change there.

If we add enabling technology, that second bar takes us up another 150 megawatts.

[Next Slide]

Looking at residential scenarios now in our two more experimental scenarios, these were only done for residential.

These show similar findings of increased load reductions, this time up to 1500 megawatts, but based on an 80 percent default participation rate versus 30 percent in Scenario 6, and that's what accounts for that difference there. Scenario 5 has a default, Scenario 6 does not.

The savings increase another 300 megawatts with enabling technologies.

[Next Slide]

One last comparison here of results.

The potential to increase load during periods of plentiful renewable generation and low loads during spring was also studied using these two scenarios, again, Scenario 5 with the 80 percent participation of default rate, Scenario 6 with only a 30 percent under optimum conditions.

The graphic shows the savings in the spring to be at 60 megawatts during the week and maybe 150 megawatts during the weekend in 2025.

More aggressive assumptions, which will be the shaded line there, shows a higher estimate of 330 megawatts of load increases during the weekend.

The one thing that MRW wants to caution is that looking at the spring and summer as bookends would not be correct. This is extremely limited experimental data, and I'll talk a little bit about that in this next slide of a summary of our results.

[Next Slide]

For all of the scenarios that we studied, the results are indicative. They're certainly not predictive or prescriptive. There simply is no existing pilot or study that's directly applicable to this kind of analysis.

There's also a significant lack of recent elasticity data for California. We found some good studies in Pennsylvania, but the climate zones don't really match here, so really there's just a dearth of data on these kinds of things, especially for customer elasticity.

And the work that Christensen did looking at the smaller commercial and industrial customers found a few interesting things there, as well.

What they’re tending to do right now is conserve across all the time periods, so we’re not getting (inaudible) that we’d hope for of people shifting into the time periods when they’re really likely to be using verse not using.

And the increases that we’re getting from the changes from the large C&I customers are relatively small, 3 to 4 percent maybe in early afternoon hours.

The conventional opt-in rates are the ones that are, again, achieving a smaller amount. It’s the default participation that really gets us a little closer to where we’d like to be, but still we’re not seeing a lot of afternoon increase, which is what we were hoping to be able to find here.

So the current and the IOU proposed rates really have no impact on residential loads during spring afternoons.

I have to point out also that most of the current programs we have were not designed with that function in mind, so that’s also an issue. We need programs that are designed very specifically if we want those kinds of results.

[Next Slide]

So what are we recommending now from this supplemental analysis; what have we learned from this?

Essentially, we need a lot more research and we need a lot more experience with residential time-of-use before we can begin to really incorporate these kinds of impacts into the forecast.

We need better assumptions about enrollment strategies. We need more about adoption of enabling technologies, and customer response about demand elasticity.

So the pilots that we hope will be forthcoming will help inform whether or how to include potential impacts in future forecasts.

Secondly, the grid impacts are again something else we really need to look at.

A number of IOUs are making proposals again to do some late shifting, but most of it is very piecemeal, so what we're also recommending is that there is a comprehensive look at all the utilities and that there's full participation of the ISO in the CPUC proceedings that are going to look at time-of-use rates across utilities to be able to someday achieve this proposed vision that we have.

Our third recommendation is that we really need some California-specific pilot studies to quantify elasticity, to clear a gap in the literature and almost nothing that looks at non-summer seasons. We really need to be able to have this kind of data to measure the potential to modify any kind of consumption behavior.

And fourth, for small and medium commercial and industrial customers, again, very little experience. They're just beginning to transition to mandatory time-of-use and default critical peak pricing and time-of-use.

We need more information again on alternative rate designs, targeted marketing and outreach, enabling technologies. Learn about how to reach these customers and to enhance their demand response capabilities.

So with that, that's the conclusion of our supplemental analysis. Any questions?

COMMISSIONER MCALLISTER: Anybody in the room have anything?

MALE VOICE: I have a question. I thought SMUD had time-of-use pricing for 2017. Is there anything in your plans about what they've done or how they derived their rates?

MS. BENDER: The question is about SMUD, whether we looked at SMUD. And certainly we looked at their evaluation to set up some of the scenarios. I believe their studies are included in MRW's literature review, yes.

COMMISSIONER MCALLISTER: You said there was a 2003 study.

MS. BENDER: It's a statewide pricing pilot.

COMMISSIONER MCALLISTER: That would be CPUC investor utility?

MS. BENDER: Yes. Yes. Yes.

So as soon as these studies are docketed, I would invite you to look at, especially the literature review. It's a very rich summary of pretty much the work that has been done. The emphasis was on California, but any good study. There are a couple in there from Arizona because there are some real good examples of quite a lot of quantitative data.

And the study from Pennsylvania as well. That one is an excellent study. It just doesn't have climate zones that particularly match what we have here. But they're all included in there both as a summary and for their applicability for doing this kind of analysis.

COMMISSIONER MCALLISTER: I actually do have a question. So we're not the ones who design the rates but we have to figure out what the impact of what the actual (inaudible) is going to be on the forecast. There's give and take there.

I guess if we do want to reach our goals, is part of your task to make recommendations about, well, we need this kind of enabling technology to get some penetration. Do you anticipate a report that would also come out with some recommendations of sort of a practice to pick up to expand the role, or really do we see it as assessing what the PUC or the POUs actually do when they pratice?

MS. BENDER: Well, we began really more looking at how, when, if we could begin to look at these kinds of impacts in the forecast. That's premature, I think, at this point.

Where this goes from here, I think will be, as you say, directly to the PUC and their proceedings. Certainly this is the kind of thing that would fit within an integrated resource plan as well, too. We just need time periods, we need rates, we need probably a wider variety of rate designs to fit this different set of customers, and I think we're just really beginning to grasp -- and Delphine can correct me if I'm wrong -- but I think looking again at the grid operations for this and being able to try to even out that load during periods in which we have the potential impact for overgeneration, that’s another significant future for more work like this. This is just like the first step in what I hope will be a number of studies taken out across the state.

COMMISSIONER MCALLISTER: Yeah, yeah, me too. And I guess I like that idea that we have this dialog in context with the forecast but then practically with each POU, in our case, so an IRP pops up so we can maybe take advantage of their IRP and get the kinds of information we need so that we’ll be better the next time around.

Anybody else?

CHAIR WEISENMILLER: I should just note that obviously a lot of what we’re talking about sounds much more like load management, and just remind people that we do have the authority under (inaudible) to set load management standards.

So certainly coming out of this there’s a particular opportunity may be something we should consider. We certainly did it the first time I was here.

MS. BENDER: That’s right we have done it in the past.

All right, thank you.

MS. RAITT: Thank you, Sylvia.

So now we'll move on to the planning area forecasts, and Malachi Weng-Gutierrez will talk about the LADWP forecast.

MR. GUTIERREZ: All right. Good afternoon, Chair, Commissioners. I'm Malachi Weng-Gutierrez and I work in the Demand Analysis Office. I will be presenting a couple of the forecast results for LADWP and SMUD. I'll start with LADWP and I'll hand the mike over to Cary Garcia, who will go over the IOUs, presenting all of their results. And then I'll finish off with a summary of SMUD, touching on the northern California non-CAISO element of SMUD now that it's a new forecasting area.

I just wanted to start also by noting that the results that we're presenting today are high level summary information, the details of which are online in tables which are linked on the notice for this workshop. So if anybody has an interest in getting a sense of the actual data behind all the presentations, it is online for comment and consideration.

[Next Slide]

So getting straight to the punch line for LADWP, there are a number of big high level things that I wanted to highlight, the first of which is that the electricity consumption in general in the mid case compared to the update for 2015 is less than it was for the update slightly, but it’s not being impacted as greatly as the IOUs.

Cary’s going to touch on those and you’ll see how the new standards are impacting the general electricity consumption for them relative to the LADWP. In LADWP it is being impacted in electricity consumption but not to such a great extent.

Meanwhile, as Ashish mentioned this morning, the PV forecast is increasing significantly in comparison to the update in 2014, and that obviously is going to impact with sales as well as the peak forecast and our revised forecast.

And then the for the peak forecast, in our revision to the peak forecast, it is actually starting at a higher point and I’ll talk about that more specifically when I get to the graph, but it’s starting from a higher point but the rate growth is a little bit lower, and again, that is attributable to the increased PV adoption.

[Next Slide]

And I do actually want to correct this slide slightly. It says the CED 2015 preliminary mid case, but we’re actually not talking about the preliminary here, this is the revised, so just note that's a correction for the slide.

The revised mid case is slightly below the update as I updated the mid case in 2025, as I mentioned, about 400 gigawatt hours lower.

And again, this is, in fact, a result of including standards into this and which also lowers consumption slightly in this case.

As I mentioned, the impact is not as severe as what we'll be seeing in the IOUs but it is significant enough to lower that mid case below what we saw in the update of 2014.

In 2016 obviously this consumption ends in mid case at about 27,000 gigawatt hours.

[Next Slide]

The new mid case growth is significantly lower in the revised case relative to the update in 2014 at about half as much as it's growing in the update. This is pretty significant and this is also related to the PV adoption, which obviously was much higher in the revised case in 2015.

[Next Slide]

Similarly, the peak demand was also impacted by the PV adoption. Although it starts at a higher point because of the weather normalization, the growth rate is lower in the revised case than in the 2014 update. And therefore, in the 2025 timeframe the points are about the same, so very similar results in the 2025 timeframe.

[Next Slide]

So here we have the PV energy associated with LADWP. As you can see, it's significantly higher than it was in the update in 2014. It's more than double certainly in the 2025 timeframe, but by the end of the forecast we are projecting here to 2026 the mid case reaches nearly 800 gigawatt hours, which is, again, significantly higher than what we were seeing in the 2014 update.

[Next Slide]

Likewise, the peak impacts are also much higher than in the 2014 update. In 2026 the peak impacts for the mid case is reaching to about nearly 200 megawatts, and that corresponds to around 450 megawatts of capacity.

[Next Slide]

One of the other elements of the demand forecast obviously is the EV consumption. And obviously Tom mentioned this morning there were numerous workshops related to the transportation energy demand forecast. I know they're busy responding to comments as I sit next to them and I hear lots of talk about those comments.

But we were able to incorporate the results into the electricity demand forecast, and this is the component of which was allocated to LADWP.

In general, they develop a statewide estimate, and as we discussed in the preliminary forecast, the statewide forecast is allocated to the different planning areas.

One of the things that we updated for the revised forecast was that not only did we use elements of population growth and economics, income, but we also weighted the results of energy consumption by VMT differences across the state, as well, so we're taking those into consideration.

We did look at projecting regionally specific energy consumption taking into consideration things like public charging station rollouts, but the uncertainty with projecting future infrastructure was a little bit complicated and so we didn't end up incorporating that, but it does incorporate regional differences in VMT.

So for LADWP, the results here in mid case correspond to about 250,000 EVs, and are almost up to 700 gigawatt hours.

The other thing I wanted to mention is that in this case the revised case here what we're comparing is the mid case is associated with ZEV mandate. The green case is where I believe the costs associated with vehicles themselves match, the EV costs match the gasoline costs in an earlier timeframe allowing them to be adopted into the market at a higher rate, so that leads to a higher demand curve for the high case. And then I believe the low is, I think it's a straight output from the model without some adjustments to match the ZEV mandate.

[Next Slide]

Nick had mentioned this morning and talked about the committed efficiency and what it's composed of. What I wanted to highlight here again is reiterating what he had mentioned.

There's a fairly narrow band here of results associated with the committed efficiency. And again, that is because of two competing elements which are influencing both the high and the low demand forecasts or the savings estimates.

In the high demand case there's a lot of economic growth for housing and construction, new houses and more floor space, which allows more codes and standard savings to be incorporated.

Whereas in the low demand case we have much higher prices associated with electricity. Which also then promote savings in that case.

So that tends to draw the cases all together, and that's why we have a narrow band there.

In the 2014 timeframe here, the portion which is attributable to codes and standards is about 3,500 gigawatt hours, and you see here that it's about total savings estimate is about 6,000, so over half of the savings is associated in 2014 codes and standards.

[Next Slide]

If you recall these charts from the preliminary, I'll try to explain what this is.

The red line is what we start with, it's the unadjusted cumulative savings. And then there was a recent study that was completed for the programs, I believe it's 2010 to 2012 programs, which led to a realization rate being estimated, and we used that realization rate to adjust the cumulative savings, which leads you to this blue line.

Now, that's the cumulative savings up until 2013. Then you add on top of that savings for 2014, and that gives you the green line. And that's what's actually incorporated into the demand forecast. So if that makes sense.

The net effect of all of that adjustments obviously is the addition of 145 gigawatt hours in 2014, and about 40 gigawatt hours in 2026.

COMMISSIONER MCALLISTER: So these numbers, the committed efficiency is already in the baseline forecast that you already got on there?

MR. GUTIERREZ: Yes.

COMMISSIONER MCALLISTER: So you're just breaking that out here?

MR. GUTIERREZ: Yes. These are adjusted program efficiencies, I believe. I'm going to look to Nick, see if that's the case.

COMMISSIONER MCALLISTER: These are existing programs that are already incorporated into the forecast or is this --

MR. FUGATE: I'm sorry, this is the first time I'm seeing this. But yeah, it looks like just 2010 to 2014, so this is not considering anything prior to those. I think Chris is probably just showing the net impact of the adjustment, the realization rate adjustment that we made to that program period of 2010 to 14.

Actually, I think -- yeah, okay. So in the forecast we also included program impacts for 2015 program year, but those weren't adjusted, which is why he's not showing them here. This is just the period that we applied the realization rate to and he's just showing the impact of that.

COMMISSIONER MCALLISTER: And then these would be incorporated into the baseline as opposed to AAEE.

MR. GUTIERREZ: Right. So these would be included in SMUD (inaudible)?

MR. FUGATE: Yes, the blue line.

MR. GUTIERREZ: The green line. The green line is the total. The green line is what is the final result of all the adjustments and the 2014 savings.

MR. FUGATE: Yeah, okay.

MR. GUTIERREZ: So that's the end result is the green line, and that's what was incorporated.

COMMISSIONER MCALLISTER: Okay. Got it.

MR. GUTIERREZ: Now that that's perfectly clear.

[Next Slide]

There are a couple of additional elements that are added into the forecast as well touching on climate change and electrification, so I wanted to pull those out.

In the case of climate change for LADWP there were 25 gigawatt hours in the mid case added to 2026, 33 gigawatt hours in the high case, 40 megawatts for the 2026 in the mid case, and 65 megawatts for the high case for the peak impact.

Again, all that's associated with climate change and I think that was touched upon this morning. Tom, I believe, talked about that.

For electrification, in addition to electric vehicles there are other elements which are being electrified; high speed rail, truck stops, other elements like that which play into electricity load and we're trying to incorporate those as well. Those are some of the additions which are associated with these numbers here.

So for LADWP the estimate we're getting is 165 gigawatt hours in 2026 for the mid case, 300 gigawatt hours in the high case.

There is a low case result here for electrification but it's fairly small so we didn't include it here.

[Next Slide]

Now taking a closer look at the specific forecasting zones associated with LADWP, there's Coastal and Inland Region.

As you might anticipate, the inland growth rates are going to be higher, and that's primarily due to the inland migration that we're seeing across the forecasts and across different planning areas and zones. Oftentimes you'll see that the inland areas are growing at a faster rate, and that's certainly the case here.

So for electricity consumption we're seeing these growth rates, in the high case over 1 percent growth rate in an annual basis for the Inland Region.

[Next Slide]

Likewise, peak demand was also growing, and here again inland areas are growing more quickly, and it's nearly 1 percent in the high case, and the peak impacts are also being affected by what is growing in those inland areas.

Oftentimes for the inland migration of the population it's residential and that obviously has a tendency to be more temperate responsive, and so you might have a higher peak impact relative to that sector as well.

[Next Slide]

All right. So now this is the AAEE component that Nick had talked about this morning at the statewide level. This is specific to LADWP.

Again, just to refresh your memory about what the high-low, mid-mid, low-high, what those are relating to is that the first refers to the demand forecast and the second refers to, I think, the set of conditions under which the AAEE is being estimated. So in the first column it’s the high demand case associated with a low AAEE values and assumptions.

So across the three these are the results in different timeframes just to give you a sense of what the impact is to LADWP. In the mid case it reaches about 610 megawatts in 2026.

[Next Slide]

And then here is the total gigawatt hour impacts. So again in the mid case by 2026 it’s about 2400 gigawatt hours.

[Next Slide]

And then to show this for the mid case in another visual representation so you can see what the trend effects are, you can see that the impact of AAEE on the LADWP baseline for the mid case is that so if you were to compare a mid savings that we just talked about to this, then you’ll see in 2026 these numbers correlate fairly well.

And the thing to note here, I think, and actually Nick had mentioned this morning as well that LADWP, there's codes and standards falling off or ending after the 2020 timeframe, and after 2020 there's a constant growth rate that's incorporated into the savings estimates, and that's what we're seeing here.

So you see there's a widening of the trends, and then after 2020 it's fairly parallel. There are some other things affecting it, but in relative terms it's fairly constant after that timeframe.

[Next Slide]

And again, this is for sales. So if we take a look at peak, that's a very similar picture. Again, we have a widening of the savings impacts on peak up until about 2020, and then you have still widening but at a different rate after that period of time.

So with that, that's all the slides that I have for LADWP, so I'm going to open it up for comments or questions.

CHAIR WEISENMILLER: Yeah, I don't know if we've got any comments online.

COMMISSIONER MCALLISTER: Is there anybody online?

MR. GUTIERREZ: There may be someone from LADWP that wants to comment, but I was going to open it up for comment from the dais first and then I'll let them speak.

CHAIR WEISENMILLER: I wouldn't be surprised if they want to do written comments.

MR. GUTIERREZ: Okay. So I believe there was someone from LADWP online. Okay. So if they haven't raised their hand, then I presume that they will then just do written comments. So with that, I will sit down and hand it over to Cary to start the presentation on the IOUs.

MR. GARCIA: Good afternoon. My name is Cary Garcia from the Demand Analysis Office, and I'm going to give a very similar presentation but for PG&E and the rest of the IOUs, and we'll get to that.

[Next Slide]

Here's a very quick summary of the forecast. As was mentioned earlier this morning, we've changed our planning area for PG&E and so now we have six climate zones. That planning area now represents the PG&E TAC area more closely.

Consumption compared to the 2014 update is a little lower, and that's due to the standards we also discussed.

And then sales and peak forecasts are also down, and that's going to be due to higher PV adoption.

Additionally, if you look at a comparison that I'll show a little later between the climate zones, you'll see there's more growth in the inland climate zones compared to the coastal areas, and I'll explain a little bit about that in a second.

[Next Slide]

So here we have our baseline consumption. As you can see, we don't have a comparison here for the 2014 update because of that shift we did with the climate zones, the planning areas. But roughly, you can see that .9 percent versus 1.29 percent in the update, so it drops down a little bit as far as consumption goes.

[Next Slide]

Here we have our baseline electricity sales. This is also down, a little flattened out there. We did an adjustment down, you can see here, so the new growth is a little reduced and the trajectory is reduced as well.

[Next Slide]

Move on to peak demand. You can see here we did our adjustment for weather normalization, so that brings the 2014 update demand line down a little bit. And you can also see the flattening out across the different demand cases due to those PV impacts.

By 2026 we're looking at about 22,000 megawatts of peak.

[Next Slide]

Move on to PV energy. Quite a bit of growth here. We have our mid case sandwiched by our high demand case on the bottom and our low demand case on the top.

By 2026 we're at about 9,000 gigawatt hours of PV energy.

[Next Slide]

Here's the same graph but with peak impacts. By 2026 we're at about 5,000 megawatts of capacity, but when you apply the capacity factor, that estimate comes out to about 1800 megawatts of peak impact.

[Next Slide]

Next, as we just saw earlier, we have our light duty EVs. Same case as before. We have our strictly model driven cases for the low demand. Mid demand is headed toward that ZEV mandate. And then our high demand case has electric vehicle prices lowering faster than, I guess, traditional vehicles.

[Next Slide]

Here we have our committed efficiency. So at 2014 we had around 15,000 gigawatt hours savings just from codes and standards alone. In total that was about 35,000 gigawatt hours.

And then you can see due to the play of the demand cases it kind of sandwiches everything pretty close together there at the end. So by 2026 we're at about 45,000 gigawatt hours of savings.

[Next Slide]

Here's this lovely chart again. We'll start off with, like Malachi, we'll start off with the red line. So that's our 2010-14 cumulative savings with no EM&V adjustments.

You go down to that blue dark line, we adjusted for EM&V, and then we applied the 2015 savings and get that green line and then have that to key off out to 2026.

So by 2026 the difference between the red and the green line is about 65 gigawatt hours.

[Next Slide]

And here's the additional impacts that we spoke about earlier.

So we have the climate change going on here. As far as energy goes, we see the difference here between the mid and the high case, about 25 gigawatt difference between those two cases.

And then we'll have the peak, so about 200 megawatts in 2026 for that mid case and then 300 in the high case due to climate change.

And then we have the core electrification and other additional electrifications, so we have about 500 gigawatt hours in 2026 for that mid case.

Additionally, we have the 135 megawatts of demand-side DR in 2026.

[Next Slide]

Here we have the breakdown of our climate zones within PG&E's planning area.

You can see there in the Greater Bay Area it's a little higher than the rest of the areas if you just compare the mid case. I guess generally across all cases it's a little higher, and that's going to be due to a little more industrial and commercial growth in the Greater Bay Area.

[Next Slide]

If we look at peak we see a slightly different story. Southern and Central Valley seem to be leading a little bit more, and that's due to the weather sensitivity of peak in the inland areas.

So we can see here the Greater Bay Area is much lower because they don't have that coastal effect that kinds of evens things out as far as peak goes.

[Next Slide]

Now we have our AAEE savings for peak. We have our mid-mid case is in the middle and the high-low and our low-high cases on the ends here.

So by 2026 we’re expecting about 1800 megawatts of peak savings.

[Next Slide]

Same charts here but with energy, so about 7500 gigawatt hours of savings in the mid-mid case.

[Next Slide]

Here we did, the baseline sales here is kind of a rough estimate because we hadn’t completed our 1.5 form because we typically have this in there, so this is going to be pretty close but these numbers are going to deviate from what we actually publish. Probably not by much but just as a reminder.

So we have our baseline sales, and then we applied the three mid cases across the different AAEE scenarios. So I guess in our mid case we’re just above 83,000 gigawatt hours by 2026.

[Next Slide]

And then this is the same chart but with peak applied, so that gets us closer to about 18,500 megawatts of peak savings.

And that would be it. Is there any

questions, comments? I think we have somebody from PG&E here or on the line.

COMMISSIONER MCALLISTER: It would be really important for PG&E and the other utilities to chime in on the individual components and dig in and help us flag anything that doesn't look right to them.

I know you've been in communication and they've sent in their information and stuff.

MR. GARCIA: Yeah, we didn't have as much time as we typically do just with some of the work we've been working on, but we're hoping if there is anything they can get that to us fast and we'll try to incorporate those changes as much as we can.

COMMISSIONER MCALLISTER: It's hard to just eyeball this and say, oh, PV looks high or PV looks low, so it's really got to be up to them to tell us what whether it passes the Smith test to them.

Thanks a lot, Cary.

MR. GARCIA: I guess we'll move on to SoCal Edison.

[Next Slide]

So once again same format. We'll just go over a quick summary here.

So now we have five climate zones for SCE within their planning area that is more closely associated with their TAC area.

Once again, electricity consumption in our mid case is lower than our update, and once again due to those new standards that we've incorporated. Some of this is offset, though, by the growth in number of households.

Sales and peak forecasts are down, and this is due to the high PV adoption.

And then once again, a lot more growth in those inland climate zones compared to the coastal areas.

[Next Slide]

Here we have our consumption. Down a little bit compared to the update but not by too much.

[Next Slide]

We have our electricity sales, which is consumption minus self-generation. You can see there is a flattening of our mid case here compared to consumption, and that's going to be due to that PV effect, and that growth rate is compared to the red line here, which is our data from the 2014.

[Next Slide]

Peak demand is a similar story. We did our weather normalization adjustment so that brings that starting point down, and then we see a fairly flat curve going out into the future to 2026, so that about 23,000 or so megawatts at peak by 2026.

[Next Slide]

Then we have our PV energy. Around 4,000 gigawatt hours difference compared to our 2014 update if we look at the old planning area. Then by 2026 it's about 8,000 gigawatt hours of PV.

[Next Slide]

Same graph but with peak. Same story. This corresponds here to about 4,500 megawatts of capacity, and that puts us at about 1,700 megawatts at peak impact.

[Next Slide]

We have our light duty EVs. As I said before, we have our low case that's strictly model driven. Our mid case (inaudible) and the high case with the electric cable prices going down.

So this number here by 2026 would correspond to about 800,000 EVs in SCE's planning area.

[Next Slide]

Efficiency numbers very similar to what I've shown before. Everything tightens up based on our demand scenarios. So about 40,000 gigawatt hours of savings by 2026.

[Next Slide]

The slope graph again. This is a little tighter there as you can see with the 2015, but we have our adjustments made with the blue line. Add 2015 to get the green, and then we carry that off.

[Next Slide]

And here's the breakout of those additional impacts that we had for the other planning areas. The additional cord electrification and then the 75 megawatts of demand-side DR by 2026.

[Next Slide]

Here we have electricity consumption by those climate zones within SCE's planning area. L.A. Metro you'll see is growing a little slower compared to those inland areas, and that's due to that migration out into the Big Creek East and eastern part of SCE's planning area.

I think the east part would correspond to Riverside and those places.

Big Creek East, I believe, is, I guess it would be the northeastern of SCE's territory, roughly.

COMMISSIONER MCALLISTER: Which do you think corresponds to Orange County?

MR. GARCIA: Orange County, I believe, is L.A. Metro is included. I think L.A. County and then

Orange County would be added up against that.

[Next Slide]

Here we have the same graph with peak. You can see here we have a lot more peak growth in that Big Creek East territory, and then we actually have negative growth for L.A. Metro.

And that's going to be due to slightly lower economic and demographic growth in that area compared to the inland areas, and then also the PV impact is going to be more significant there.

[Next Slide]

Here we have our AAEE savings. Once again, we just have our three mid cases sandwiched between our high-low and should have been low-high on the other end here. That's a typo. But about 2,000 megawatts of peak savings by 2026 for AAEE.

[Next Slide]

Same story here but with energy, so that peak impact translates to about 8,600 gigawatt hours of savings.

[Next Slide]

Once again, this is our estimate of SCE's baseline sales and the impact from AAEE. And so we have our new scenarios at the bottom there.

So by 2026 we're expecting about 83,000

gigawatt hours of savings in the mid-mid case.

[Next Slide]

Same thing for the AAEE scenarios impact on the baseline peak, and there were about 18,500 peak savings by 2026.

That would be it. Any questions or comments?

COMMISSIONER MCALLISTER: No, this is a good run down. Same comment that Edison kind of needs to step in here. But I am heartened that the AAEE numbers are not small, they’re 9, 10 percent over energy, more than that of the demand. So the mid case from the mid baseline to the mid-mid AAEE it looks like it’s 12 or 13 percent demand reduction, so that’s pretty impressive. It would be interesting to hear what Edison would have to say or what the reasons behind the higher capacity reductions than energy on the percentage basis.

CHAIR WEISENMILLER: But I think the other thing is certainly true for Edison and for PG&E is that historically we really had to work to line up overall forecast.

And now that we’re doing the desegregation, then the question is, even if we’re in relative agreement overall, are there real differences across the areas.

Obviously, I'd be very surprised if, as we continue that we're going to be in very much agreement initially, though over time we should be able to work out where the differences are.

COMMISSIONER MCALLISTER: Yeah.

MR. GARCIA: So we have Ed Martinez from SCE on the line, so I think he's going to be able to provide some comments and additional insights.

COMMISSIONER MCALLISTER: Go ahead.

MR. MARTINEZ: Hi. Thanks for the opportunity for me to answer that question. Unfortunately, I don't have any exact answers for past discussions that took place but I can confirm that Orange County is part of the L.A. Metro region.

And that coincides with what we're getting from our economic data vendors with the Department of Finance mostly from population (inaudible) is in our inland area, Inland Empire, and a little sliver of the San Joaquin Valley.

I do have two questions and two comments.

In regard to the weather normalization, I think maybe perhaps after this meeting if you could provide a little bit more detail or if you could walk us through exactly how the change in weather normalization happened. That would help us reconcile some of the differences that we have in our forecasts.

One quickie question that I have right now. Earlier when you were talking about the statewide changes, the building standards were mentioned. The changes in the standards, did that filter down into the IOUs like SCE and the other IOUs?

MR. GARCIA: Yeah, I believe all those changes filtered down to everybody, yeah.

MR. MARTINEZ: Would you be able to quantify that, then, like how much was weather normalization, how much was it the standards?

CHAIR WEISENMILLER: On some levels, probably. I was going to say certainly the weather normalization was a big issue the last time, and we certainly encourage everyone to drill down and get it lined up now instead of at the adoption hearing.

And generally as we go through like with the building standards, what's going to drive the impacts in Edison is, embedded in the staff models are forecasts to say how much new construction is occurring in various locations and split between multi-family and single family. So that depending upon what the underlying forecast is for that new construction in, say, Orange County, that will then show how much the building standards impact Orange County, or Edison, as opposed to PG&E.

And because really new construction is driven back by the econ/demographic forecast of where the growth is in your service area. So that would flow through on some level.

MR. GARCIA: Yeah, the weather normalization would be another step of that, though. I don't know how that plays out as far as the building standards goes.

MR. GORIN: But the weather normalization, I think, was provided. It’s just for 2015 for the peak. And I think that --

MR. GARCIA: We’re in the process of finishing that up right now, actually. That’s why...

MR. GORIN: I thought he had sent the utilities the weather normalization estimates a week ago. But has SCE not received them?

MR. MARTINEZ: As far as I know, I haven’t. I can ask around.

MR. GARCIA: Yeah, they should have been sent out to Tong Yang. I know she typically is our contact, but I think there was a change.

MR. MARTINEZ: She’s out for the rest of the year, but I can follow up with Miguel.

MR. GORIN: Yeah, because I had a note from Chris that Miguel said the weather normalization was okay with the utilities, but probably be good to check on that.

MR. MARTINEZ: I'll follow up.

MR. GARCIA: I do recall that email. I'll check my email and see if I can forward that to you, Ed. I think I have it in there.

MR. MARTINEZ: I appreciate it.

MR. GARCIA: No problem. Would that be the last of your comments?

MR. MARTINEZ: Yes.

MR. GARCIA: Okay. Thank you, Ed.

All right. Okay, we'll move on to my last presentation for San Diego Gas & Electric.

[Next Slide]

Go to our forecast summary.

No change to this planning area, it's going to be the same.

We do have a drop in electricity consumption compared to the update, but this has been offset by the growth in EVs in San Diego's territory.

Sales and peak are also down more significantly, and this is due to higher PV adoption.

[Next Slide]

Here we have our electricity consumption. You can see here now our high case is closer to what the update was in 2014, so now we have this lower demand for the mid case, topping out at about 24,000 gigawatt hours by 2026.

[Next Slide]

Electricity sales, consumption minus self-generation. You can see the flattening out of our mid demand curve out to 2026. Significantly lower than the update’s demand.

[Next Slide]

Same chart but for our baseline peak demand. Once again we have weather normalization that brings us back down, and then we start off the growth, but that PV adoption levels everything out.

[Next Slide]

Here we can see our PV energy. Quite a bit higher than what we had in our 2014 update. By 2025 it looks like we’re going to have about 2,200 gigawatt hours of PV energy.

[Next Slide]

Same chart with PV peak impacts. Once again, quite a bit higher than what we had for the 2014 update, topping out at about 500 megawatts of peak impact out to 2026. And this corresponds to about

1300 megawatts of capacity.

[Next Slide]

Light duty EVs. Same story as before. This case, though, we can compare that to the planning area because we didn't make any changes so we can see our old update demand case there in the middle of the three curves. So this would correspond to about 250,000 EVs by 2026 if you look at our mid case.

[Next Slide]

Another committed efficiency graph here. Everything's sandwiched up together, and you see that stat up there about 4,000 gigawatt hours from just savings in codes beginning in 2014.

Just a reminder. These are also broken, the efficiency committed savings for programs and price effects, as well as building and standards, in our demand forms for each of the planning areas.

[Next Slide]

Every time I look at this chart it always takes me a second to get it all in there. I've seen it a thousand times but...

MR. FUGATE: Cary, can I just correct what I said earlier so --

MR. GARCIA: On this chart?

MR. FUGATE: -- come back to me now, I

remember Chris asking me for this data.

So the blue and the red is from last cycle where we didn’t have the 2010 to 2012 EM&V results, and so I think what Chris is showing here is that we added another year of savings and applied the 2012 EM&V results and that’s the net effect, we’re still in the neighborhood of where we were.

COMMISSIONER MCALLISTER: Yes, I think I deciphered that, too. It’s invisible, but there is a line between the 2014 blue and the 2015 green.

MR. FUGATE: Yeah.

COMMISSIONER MCALLISTER: That’s the actual curve that’s built into the forecast itself.

MR. FUGATE: Yeah. Sorry for the confusion on that.

MR. GARCIA: We should do a crowd source and figure out how to graph this. All right, so we’ve got it. We’ll move on.

[Next Slide]

So here we have our additional impacts.

So climate change impacts here, 20 megawatts of peak in our mid cases by 2026, and 40 megawatts in the high case. San Diego is a little smaller than everybody else so these things get dropped down a little bit.

Additional electrification, 40 gigawatts compared to 80 gigawatts from the mid to the high case in 2026.

And then we have about 60 megawatts of demand-side DR in 2026.

[Next Slide]

Here we have our AAEE savings again, broken out across those three mid cases and the high-low and the low-high case for AAEE. Peak impacts are about 450 megawatts by 2026.

[Next Slide]

Same thing but now we have energy, 1900 gigawatts by 2026.

[Next Slide]

And then we have our baseline sales for the mid demand case and then the three AAEE scenarios, the low, mid and the high applied here.

So energy savings we're at about just under 1,000 gigawatt hours of savings.

[Next Slide]

And then the peak impacts here, same thing, pretty flat demand curve over there.

And then if you look at the mid-mid case, that brings us to about 42.5 as far as the peak savings.

That would be about it. Questions?

Do we have anybody from San Diego?

COMMISSIONER MCALLISTER: Come on down.

MR. SHERMEYER: Thank you for the opportunity. My name is Ken Shermeyer and I'm the electricity forecasting manager. A few comments.

We just received the forecast so we're still looking into it, but we're seeing the same trends in our own forecasts that we're seeing in the CEC's forecast.

And we look at on a managed basis, too. We think it's coming to fresh energy efficiency savings. We're seeing it today.

Some of the other things we're going to look at are the EV component, and I'd like to have our electric vehicle group check that over. But in the recent past it's matching up pretty well.

For the PV, we like that we saw the improvement in the forecast. I think it'll be important to get Ashish year-end 2015. I mean, I think it's growing pretty fast and to give him the most updated information available, I think will be important.

My only other comment is there are a lot of policy changes that have just recently happened, and we may not get them in this forecast. Is there a possibility of maybe putting it in the ’16 update?

CHAIR WEISENMILLER: Actually, no. What we’re going to do, and this has been something we’ve talked about certainly with the other agencies, is that it’s really going to take us all of next year to learn how we’re going to ramp up the methodology to really incorporate 802 and 350.

We’re always in this weird position. On the one hand we’re going to be adopting this IEPR soon and we’re going to be kicking off the next one almost at the same time, as the IEPR team over there is nodding glumly. So we really have the change for Chris’s group to work through how do you do this and how to get the data. We just don’t see a chance, nor does the PUC see a chance that we could get it together next year.

But we really want everyone to focus next year on how do we do it right going forward, because the 802 and 350 stuff, we’re talking about really, really big changes. And at the same time if you look at, like PV, there’s huge changes going on there.

So it’s really going to be important to get it right, and I think we’re all going to have to spend every creative ounce of energy we have next year working through how to get it right so the following year we really come up with a bang-up product.

COMMISSIONER MCALLISTER: Yeah, I totally agree. It used to be that the IEPR was every two years and it’s taken on more heft recently. But to have really done well every two years is probably enough, even though we all feel like the world is shifting under our feet, still, I think if we can have the methodology discussion how would we do it.

And everybody can go do their dry runs next year and figure out how to get their heads around it and bring some numbers for sure, but then commission a new machine for 2017.

CHAIR WEISENMILLER: Yeah. And again, I should be pretty clear. There will be an IEPR next year, and Karen Douglas will be the lead on that. It’s going to deal with a lot of interesting stuff, particularly following up on DRECP and some of the landscape level environmental planning.

So again, that’s going to be a huge effort next year, and the other topics. But certainly for forecasting demand and supply as a set, think methodology, think data, think what do we really need to do to do it right going forward. And not just do minor tweaks, but let's really think creatively about that big picture.

COMMISSIONER MCALLISTER: Yeah, 350, as you read through it, there's a little room for interpretation, but there are lots of different elements of the forecast that are called out that we need to get our heads around.

Now, how analytically robust each element needs to be, I think that's part of the methodology discussion. But we have to get more granular and we have to try to segment better and get not just in PV and not just in energy efficiency, but potentially some of the other buckets that overlap of different kinds of resources, we need to get to some understanding of how we are or are not going to try to analyze and (inaudible).

So the methodology discussion, I think it's really exciting to be having it, it's very necessary, and it's actually more important than the particulars of a given forecast we might be given here.

CHAIR WEISENMILLER: Again, just building off of our earlier back-and-forth on 758, I mean, it's huge, and we don't have the data to really at this point do it, or necessarily the analytical tools, but we have to get there. Same on 802

Anyway, we're looking for a lot of your help next year. It's probably going to be more in the DAWG type of format than the hearings.

MR. SHERMEYER: And we enjoy participating in the DAWG group, we think it's a great venue, and look forward to bringing our ideas.

That's all I have.

COMMISSIONER MCALLISTER: Well, thank you. Thanks for coming up.

MR. GARCIA: Thanks, Ken.

MR. GUTIERREZ: All right, Malachi here. Thank you, Cary.

All right, so hometown for last. Since SMUD was one of the territories where we did do an adjustment to the forecasting zone, I'm going to be touching on NCNC as well as SMUD throughout this presentation, touching a little bit on each in different areas. I'll try to note that when I go through that I'm now talking about NCNC versus SMUD. I may not catch them, but they are in the titles of the slides themselves.

[Next Slide]

So again starting out with the SMUD service territory. The big picture items, the big impacts is basically that the electricity consumption is only slightly reduced compared to 2014 update, and that's primarily because of the higher population growth.

Estimates, the sales and peaks forecasts have obviously been reduced compared to 2014 because of the PV adoption. In the case of the peak, no so much because of the peak factors being utilized are different than in 2014, but we'll get to that in a moment.

And then just in general if you look at the NCNC planning area, the growth rates that will show again at the summary table at the end are fairly fast compared to other areas in California.

[Next Slide]

So starting with the baseline electricity consumption. The new mid case grows faster in the near term, and then it slows down a little bit later on, so we do see this crossing over of that mid case with the 2014 update mid case.

And I did want to say partly this is because we're having both population growth and then we have standards coming in that are countering those, and so that those are competing factors again in our general electricity consumption is.

[Next Slide]

So peak impacts here are slightly lower, again reduced because of the PV adoption, the higher PV adoption, but not as significantly as we saw, say, for LADWP where the growth rates were half of what we were seeing before.

[Next Slide]

And then likewise the peak demand is slightly lower. But again, because of the different peak factors that are being utilized for the 2015 revised number versus 2014, it's not as low as you might imagine it to be.

[Next Slide]

And then here, again we have PV energy being significantly higher than in the past. Not as high was what you saw in some of the IOUs or the LADWP but still significantly higher.

One of the things I wanted to correct on the slide was that it does say this is a comparison between the revised PV energy and the updated 2015. This is obviously not 2015 update, that's 2014 update mid case is what we're comparing here.

[Next Slide]

And then the corresponding peak impacts as represented here. Again, higher peak impacts than what we saw in the 2014 update.

What I wanted to note here is there is a couple points that are not present in the high case, so I’m just going to say that the 2025 high peak impact was 172.7 megawatts, and then in the 2026 timeframe for the high case it was 199.5, so nearly 200 megawatts in the high case. Again, those are not on the slide because they got cut off.

[Next Slide]

So then we also have this is the regional EV impact to demand. The representation here in the mid case in 2025 is about 80,000 EVs. Obviously the mid case again corresponds with the ZEV mandate compliance, or the most likely compliance scenario. That obviously could change depending upon how OEMs comply with the ZEV mandate, but this is corresponding to the ARB’s most likely compliance scenario and how they have defined that.

And as before, the high case is where costs are becoming more competitive with gasoline vehicles, thus leading to a higher adoption. And the low is of a fairly flat outlook (inaudible).

[Next Slide]

CHAIR WEISENMILLER: Do we have in our forecast is light rail for SMUD? My impression is the Board is really committed to try to expand light rail, maybe to Davis next. And their way in part to deal with ZEV is light rail as opposed to necessarily just vehicles.

MR. GUTIERREZ: That’s a good question. I don't know how you’d transfer those credits. I guess you’d have to sell the credits to the obligated party.

CHAIR WEISENMILLER: Well, I’m thinking load. So I’m saying on the load side the Board at this point is really focused on growing light rail in Sacramento.

MR. GUTIERREZ: Yes.

CHAIR WEISENMILLER: At least when I push them on where is their program for charging, they point to what they’re doing in light rail, so I’m trying to understand where we’re picking up light rail in the forecast.

MS. BAHREINIAN: We do pick up light rail in our travel demand models, in urban travel, light rail demand is reflected.

On top of that, one of the scenarios that we forecasted, we changed some of the buses and urban transits after 2020 from natural gas to electricity. So we took care of those two in another model.

MR. GUTIERREZ: So the question, then, is that reflected in the electrification numbers as

opposed to the EV light duty?
MS. BAHREINIAN: No, it is not reflected in the EV.
MR. GUTIERREZ: It’s in electrification then.
MS. BAHREINIAN: Yes.
COMMISSIONER MCALLISTER: But you do pass that consumption over to the forecast(inaudible).
MS. BAHREINIAN: Yes, the transportation electricity demand forecast that we have in the transportation covers the light rail and buses and electric buses.
MR. GUTIERREZ: Thanks. What threw me there, there was a comment that they were talking about in the context of the ZEV mandate compliance that light rail doesn’t really play.
CHAIR WEISENMILLER: Anyway, they can’t blame the PUC for not charging.
[Next Slide]
MR. GUTIERREZ: All right. So here we have, again, moving from SMUD now to NCNC, this is a reflection of the committed efficiencies across the entire NCNC planning area.
And again we see a very narrow band of results here again from those competing elements in

the forecasts. So as high economic development leads to more codes and standards savings versus the price effect of any other competing cases. So that's why again the narrowing of these efficiency numbers.

[Next Slide]

This is the non-crowd sourced visualization of the adjustments. So again, focusing back on just SMUD. So I believe we got it now so the red line is the unadjusted numbers up until 2013 and then the blue line is now adjusted by the EM&V study, incorporating the realization factor of those programs.

And then adding on top of that in the 2014 timeframe is the new savings from different programs, and that's in the green line.

So as Commissioner McAllister said, what's incorporated into the forecast is really from the blue line from 2010 to 2013, and the green line from 2014 to 2026.

[Next Slide]

All right. So for SMUD some of the additional impacts and magnitude of those impacts are presented here.

Again, we only have climate change and electrification as modifiers here. In the high case for climate change the consumption is increasing by 70 gigawatt hours, peak is impacted by 45 megawatts.

And then for electrification, in the high case we’re looking at an additional 30 gigawatt hours of consumption.

[Next Slide]

As I mentioned at the beginning, the growth rates here for the NCNC area is pretty significant. These are fairly high if you do a comparison across of these with the IOU growth rates, most of these are higher. And again, it’s because we’re still populated in Sacramento. It’s such a great place to live and we have a new arena going in, and I don't know how else to market it. But we do see a lot of growth in this region, and again, it’s driven a lot by population migration.

[Next Slide]

Likewise, peak impacts here are pretty significant relative to the other utilities. The highest being obviously in the Turlock Irrigation District.

[Next Slide]

Getting to SMUD’s AAEE. Again, these are the savings associated with AAEE estimates for SMUD territory, these are the peak impacts. In the mid-mid case we’re looking at over 300 megawatts, and still pretty significant.

[Next Slide]

And the associated gigawatt hour impacts are over 1100 in the mid case.

[Next Slide]

And now the resulting graphic estimating the impacts. Again, Cary noted that these are just rough estimates and that the final actual impacts would be identified in the Form 155 note. So these are just what the sales would look like from the baselines given the mid AAEE savings that were just presented in the previous tables.

So this is for sales, and it looks as though obviously the mid AAEE savings is sort of flattening sales through about 2022, and then you have a slight increase after that point, likely because of PV adoption and other things, population growth.

[Next Slide]

And likewise the similar set of trends in the peak case. A fairly flat peak or managed peak estimates through about 2020, 2021, and then you have a slight increase through time.

So that is it for the slides that I have for NCNC or the SMUD area, and so I’d be happy to answer any questions.

CHAIR WEISENMILLER: Is there anyone here from SMUD, on the line or here?

MR. GUTIERREZ: No. I thought that there was going to be no one from SMUD commenting, so I'd be surprised if they were.

If there is anybody from SMUD, would you like to -- or NCNC maybe? Turlock?

Okay, doesn't look like it. So any comments in the room or questions from the Commissioners?

COMMISSIONER MCALLISTER: No, I think I'm pretty clear.

So that's it for presentations, right, Heather? So maybe we can remind everything when the comments are due and the process. Thanks.

MS. RAITT: Bob McBride has his hand up. I don't know if there's something that he wanted to add. We have another person.

MS. VISWANATHAN: Hi, my name is Kala and I work for the Natural Resources Defense Council, and we wanted to thank staff and the Commission for their hard work to produce the 2015 Demand Forecast.

We support the Commission's effort to create a more granular forecast by including twenty geographic forecasting zones. And moving forward, we recommend the Commission to work with the joint agencies to improve the granularity of the AAEE forecast as well.

We also support the swift inclusion of the 2015 Title 20 appliance standards in the baseline forecast.

While we commend the forecast for including SMUD and LADWP, the AAEE forecast excludes more than a third of energy efficiency savings from POUs. We recommend that the Commission include energy savings from all mid-sized POUs energy efficiency programs.

Looking at the 2013 managed forecast and comparing it to actual energy consumption from 2014, the managed forecast was more accurate than the baseline forecast. So relying on energy efficiency as a resource is the most reliable plan, and the 2015 forecast will save an equivalent of eleven power plants by 2025.

We look forward to working with the Commission next cycle to implement SB350’s goal of doubling AAEE and also working on AB802 (inaudible).

Thank you for considering our recommendations.

CHAIR WEISENMILLER: Thanks very much.

I wanted to make sure we also invited you to participate. Next month we may be kicking off on the IRP side and obviously we'll be doing that in the context of POUs, and certainly encourage vigorous participation by the NRDC in the IRP process.

MS. RAITT: Anyone else in the room?

MR. BENGTSSON: This is Nathan Bengtsson from PG&E. I just wanted to make sure you all knew we were here, and we will be sure to (inaudible). I know our folks have been really engaged with DAWG but we'll take a look and make sure to get you any comments.

CHAIR WEISENMILLER: Typically, the utilities don't have enough time between (inaudible) hearing, but we'll do general comments now but then very detailed written comments. We're looking forward to getting those from you.

And again, if you could look at some of the area forecasts, we'll start moving with more granularity we're certainly going to have differences that we need to work through.

MR. BENGTSSON: Absolutely. We'll make sure to do that.

CHAIR WEISENMILLER: Great.

MS. RAITT: Okay, if that's everybody in the room, then I'll just remind you that written comments are due Thursday, December -- excuse me. If we could just pause a moment and see if the people on the phone want to make -- if you could mute your line unless you wanted to make a comment.

Okay. Sounds like we don't have anybody on the line.

So again, if you could submit written comments by December 31st, and information on how to do that is here on the slide and also in the notice.

COMMISSIONER MCALLISTER: So with that, I will wish everyone a wonderful holiday reading the IEPR, preparing your comments, and between cups of eggnog. I know I will be doing the same.

Thanks for all the good work from staff and thanks to the agencies for being here and paying attention. And we are getting there, getting close to the finish line on this year's IEPR, just in time to start the next one, obviously. Good stuff.

So thanks everybody for all your help.

CHAIR WEISENMILLER: Yeah, thanks for your help and happy holidays.

(Adjourned at 3:34 p.m.)

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REPORTER'S CERTIFICATE

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

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IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of January, 2016.

____

Shanalee Gallagher
CER-830

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IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of January, 2016.

Terri Harper

Terri Harper
Certified Transcriber
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