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BEFORE THE

CALIFORNIA NATURAL RESOURCES AGENCY

CALIFORNIA ENERGY COMMISSION

In the matter of,	)	
	)	Docket No. 16-IEPR-05
	)	
2016 Integrated Energy Policy	)	
Report (2016 IEPR Update)	)	

IEPR COMMISSIONER WORKSHOP ON METHODOLOGICAL IMPROVEMENTS TO THE ENERGY DEMAND FORECAST FOR 2017 AND BEYOND

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, JUNE 23, 2016

10:00 A.M.

Reported By:
Kent Odell

APPEARANCES

Commissioners

Chair Robert B. Weisenmiller, Energy Commission

Commissioner Karen Douglas, Energy Commission

Commissioner Andrew McAllister, Energy Commission

CEC Staff

Heather Raitt, Project Manager, IEPR

Presenters/Panel Members Present

Cary Garcia, Energy Commission Staff

Asish Gautam, Energy Commission Staff

Melanie McCutchan, Pacific Gas and Electric

Ben Sigrin, National Renewable Energy Laboratory

Erin Boedecker, U.S. Energy Information Agency
(via WebEx)

Chris Kavalec, Energy Commission Staff

Jeff Billinton, California Independent System Operator

Hongyan Shen, Southern California Edison

Alan Sanstad, Energy Commission Expert Panel

Bob Emmert, California Independent System Operator

Ken Schiermeyer, San Diego Gas & Electric

Sam Ray

Khala, NRDC

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P R O C E E D I N G S

JUNE 23, 2016 10:00 A.M.

MS. RAITT: Welcome to today's Commissioner Workshop on Methodological Improvements -- that's a mouthful -- related to the Energy Demand Forecast for 2017 and Beyond. This workshop is part of the 2016 Integrated Energy Policy Report Update process.

And I'm Heather Raitt, the Project Manager for the IEPR.

Quickly, I'll go over some housekeeping items. Restrooms are in the atrium. There's a snack bar on the second floor. If there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

Please be aware that today's workshop is being broadcast through our WebEx conferencing system and it is being recorded. We'll post an audio recording in a few days and a written transcript in about a month.

I wanted to thank our presenters for being here today and ask that you do stick to the time allotted for your speaking. And I will remind us of our limitations in time as we go along for the day.

At the end of the day we will take public comment and request the comments be limited to three minutes per person. There are blue cards at the entrance. You can go ahead and give them to me, if you wanted to make comments at the end of the day.

And for WebEx participants, just use our chat function to let us know that you'd like to make comments.

If you haven't already, please sign in at the entrance. And written comments are welcome, and they're due July 7th. And the notice for this workshop, which is posted online, along with the presentations and other materials, provides instructions for submitting written comments.

So, Commissioner Douglas.

COMMISSIONER DOUGLAS: All right, thank you. Well, I just want to welcome everybody to this workshop. And I think I will actually defer to the Chair for substantive opening comments.

CHAIR WEISENMILLER: I really want to thank everyone again for being here today.

Obviously, one of the Energy Commission's key roles in State policy is the demand forecast. And I think over the decades one of our really leading areas, areas leading the country is demand forecasting in a way that incorporates the policy initiatives of California. And, certainly, with both SB 350 last year, and 802, we have to step up our game in this area.

And this is one of the foundational ones. We want to look a lot at methodological issues. And some of the areas that we've teed up, or know from the last time we have to do better on.

Having said that, once we get into July, there's going to be a couple more workshops that are more focused on the doubling down on energy efficiency.

And again, looking at Heather, I don't think either or both of those are noticed, yet. But anyway, just to give people a preview of coming attractions, we're going to again try to really drill down on sort of how do we incorporate doubling down on energy efficiency.

And then, more at the end of the month, and these are sort of joint activities, first with President Picker, Steve Berberich and I. And then the other one is also with the PUC Commission, particularly Commissioner McAllister and Commissioner Peterman on what are our goals as we try to translate 802 and 350 into specific actions.

So, anyway, I'm sure there's even more than that, but at least that's sort of the sequence. This one and then the two next month.

So, again, thanks for being here today. I think this is a topic which you can tell we're putting a high priority on, particularly in terms of the 802 and 350 implementation, and this is part of an overall comprehensive program.

Commissioner McAllister is, obviously, very heavily involved in this. He's asked me to have us start without him, but I'm sure he'll be here real soon. So, with that --

MS. RAITT: Great. The first speaker is Cary Garcia, from the Energy Commission.

MR. GARCIA: All right, good morning. So, I think I'm just going to -- we have plenty of presentations on here, so we should probably just start rolling through this.

We'll just do a quick overview of what we're going to cover today in our agenda. So, first up we'll have our behind-the-meter photovoltaic adoption and impacts presentations. We have PG&E, as well as NREL, and the EIA here to present on their methodologies or their take on forecasting PV adoption.

And then, next, we'll go into weather normalization with Chris Kavalec.

After lunch, we're going to head into the analysis of peak shift. We have representatives from the ISO here, as well as Southern California Edison.

And then after that, we'll head into long-term forecasting of hourly loads. We have our expert panel here, Alan Sanstad. And we also have another guest from ISO, Bob Emmert, and a representative from San Diego Gas & Electric.

At the very end, or lastly I guess, we'll go over a geographic disaggregation, once again with Chris Kavalec.

So, we'll get started with Mr. Asish Gautam.

MR. GAUTAM: Good morning, everyone. My name is Asish Gautam and I'll be going over some data issues and updates we want to do to help forecast PV adoption. These updates and changes were motivated based on stakeholder comments we received as part of the 2015 IEPR. The IEPR demand forecast is used in other proceedings, outside the Energy Commission. And so, the rapid increase in behind-the-meter PV has implications for the demand forecast.

As Cary mentioned earlier, one of the impacts we're all looking at is the possibility of a shift in the system peak due to continued adoption of PV.

Let's see, so first I want to start off to talk about how we've reorganized our database for quantifying the number of projects in the State. This is kind of the starting point to develop the forecast.

So, historically, we've relied on data from rebate programs, such as the California Solar Initiative, the New Solar Homes Partnership, and the Solar Generation Rebate Program. And the reason for relying on data from a rebate program had to do with, you know, they were easy to access. They were updated fairly frequently.

And in the case of the California Solar Initiative, they collected and published a wealth of data. And so, it was more convenient for us to work with the rebate program data.

And as long as there's funding and participation through these programs, the data from rebate programs can be a reliable indicator of installations in the State.

However, after the 2013 IEPR we became aware of a discrepancy between the CSI rebate data and what the IOUs were showing through their interconnection data. You can see I have a table here that shows the discrepancy for 2012 and 2013. And you can see by 2013, the discrepancy becomes very large. We're missing almost half, more than half the data for San Diego, about 40 percent for PG&E, and about 12 percent for San Diego. So, this was something that we had to address quickly.

And so for the 2015 IEPR, we took a proactive approach and requested interconnection data through our forms' instructions.

Another development that happened here was the PUC issued a decision directing the IOUs to publish their NEM PV interconnection data. And this is what we are using currently, going forward for the IOUs. We have used it for the presentation later today on the peak shift and we are also going to use that for the 2016 IEPR update.

So, even though we have a source to get timely interconnection data for the IOUs, we're still going to issue an interconnection data request for the 2017 IEPR. And this has to do with some issues we discovered with the larger POUs.

Just kind of a way of background, when SB 1, or Senate Bill 1 was passed back in 2006, this was the legislation that created the CSI program. And it also asked the POUs to also offer a similar type of program for their customers, and that they would report on their rebate activity to the Energy Commission.

And when we issued the data request for the 2015 IEPR, we thought we'd take a look at what these POUs are reporting to us through their interconnection data, and what they're also reporting to us via their SB 1 reporting requirements.

And we discovered that, just like with the IOUs, there are some large differences between interconnection data and the rebate program data. And we’ve followed up with a few of these POUs to get a sense of why this is happening.

And just like in the case with the IOUs, you know, rebate levels are stepping down. There’s a lot more installations going on. Costs have come down. And so, there’s installations happening, but not going through a rebate program.

There’s a table here to show how large the discrepancy is here. Obviously, the installation, the kilowatts installed are not as large as what we had for the IOUs, but the discrepancy’s pretty significant. And if you’re trying to estimate behind-the-meter generation at the statewide level, we have to get a handle on these discrepancies. And that’s why we want to continue to request PV interconnection data for the 2017 IEPR.

So, this slide, again I was trying to show why it’s very important to continue collecting the interconnection data. There’s a lot going on here, but let’s try to take it one step at a time here.

So, the green curve there goes with the vertical axis on the left. This is from the PUC/IOU/NEM interconnection data. It's current until 2015. Again, we have about 4,500 megawatts of PV installed as of 2015.

The blue and the red curve go with the vertical axis on the right. And the units there is a dollar per watt. The sources for these two comes from LBNL's "Tracking the Sun" report. The blue curve shows the trend in the median installed cost over time. And the red shows the trend in the module cost.

We're just trying to show that, you know, the increase in PV adoption over time is related to decreases in system cost. But there's also strong policy support at the state and federal level for PV.

And in the green text box there, put a few programs and legislation that have -- that I wanted to kind of highlight, that have had a big impact on PV adoption.

So, we start with the Energy Commission's Emerging Renewables Program back in '98. And then a few years after, the PUCs Self-Generation Program. And then, you can see the installations are trending up, but it's not until SB 1 passes in 2006 that it gives a shot in the arm to the industry, and installations take off. And, you know, the costs were still coming down.

And then in 2009, we had the Federal Recovery

Bill. It had a number of provisions for clean energy. One that I wanted to point out was that it removed the cap on the tax credit for residential systems, which was a big driver to promote residential systems after that.

The two bills on the right, AB 327 and the extension of tax credit, and it's too early to see the impacts of these new legislation. But I wanted to just put it there because there was a lot of concern last year about what would happen to the tax credit, would it get extended or not. And, you know, the credit was extended towards the tail end of 2015.

Obviously, that's going to keep the momentum going. So again, there's a big need to have, to collect interconnection data so you can kind of capture all these impacts.

And then, AB 327 has three components that, you know, they're still kind of being worked out. But they're going to have significant impact on adoption.

So, the first one is the reform of residential retail rates, the old tier flagging. And then, it also calls for a possible move to time of use rates, I believe by 2020. Those issues are still being --

CHAIR WEISENMILLER: I don't think President Picker would agree with the word "possible".

MR. GAUTAM: Yes. Yes, so there's a big focus to get to default time of use rates by 2018 or 2020 time frame.

And then the second part, which is pretty important, is the development of the NEM Successor Tariff. And that's a key thing because as of right now I believe SDG&E's very close to meeting their limit and PG&E's not too far behind. Edison has some room to go.

The third component of AB 327 is the development of the distributed resource plans. And, basically, it's asking the utilities to play for and accommodate more distributed energy resources in their planning.

So, now, the State has a number of goals for clean energy. And if you don't have the data to track how you're meeting your goals or how your process is, you know, you can't figure out what's going on. And so, this is very important to have timely and accurate access to interconnection data.

The other takeaway I wanted to kind of mention was that it took about 12 years to get to the first gigawatt of installation and the next gigawatt only took two years. And then, the third gigawatt only took one year. And I've looked at the most recent interconnection data, as current until the first part of 2016, and if you take what's already been installed and assume that the rest of 2016 follows, you know, the average additions of the last three years, then 2016 is going to shape out to be another year of at least a gigawatt of additions. And that will get you to about 4,500 megawatts of PV.

I've been tracking and compiling this data since 2008. And I remember the original CSI goals of having 3,000 megawatts of behind-the-meter PV installed by 2016. Back then it seemed like a lofty goal. But, you know, here we are and we've kind of blown past that goal by a wide margin. And so, I just thought I'd point that out.

CHAIR WEISENMILLER: Before you leave that chart, are the data points January 1, July 1 or December 31st when it refers to, say, 2015?

MR. GAUTAM: This is just for the whole year.

CHAIR WEISENMILLER: Okay, so it would be December 31st of 2015?

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Okay.

MR. GAUTAM. So, earlier we talked about the need to have data behind the installations and that gives us the installed capacity. To account for the impacts on the demand forecast we have to translate that installed capacity to energy and peak impacts. And to do that we need PV production profiles.

In prior IEPRs we've relied on static shapes, whether we've got them from the rebate, CSI, EMV studies. Earlier IEPRs we used the shapes from the New Solar Homes Calculator. It's, I believe, very similar to the PV Watch Tool.

There were a few things going on that caused us to kind of question the shapes that we had been using. First, we're always thinking about how to disaggregate the demand forecast further, and so we've expanded our forecast zones from 16 to 20. So, with new zones, we need new PV shapes to reflect the change in geography.

And when we were engaged in the -- in our analysis of the peak shift, when we overlaid our load data we could see patterns that were obviously related to weather, but the static PV shapes were not really -- kind of confounding things.

So, what we wanted to do was to find PV shapes that kind of went with the load data and the weather, and the behind data. So, one of the challenges is getting access to this data.

So, we reached out to the IOUs for assistance. And it turned out, as of right now, PG&E and Edison don't have a low reach of sampling for metering generation profiles from their customers.

SDG&E, on the other hand, has been metering customers and it's a sample of about 500 customers that shared their data with us. We are using their generation profile and we did use it for the peak shift analysis later on.

And we've also received the production profiles from SMUD. So, that still leaves us in the dark about what to do about PG&E and Edison.

And, fortunately, it turned out that as part of the PUC's EM&V study of the CSI Program, they hired a contractor, Itron, to install separate meters to quantify generation from about 500 systems, starting in 2010. This data was available publicly, I believe late last year. And so, you know, now we have a source of actual production data for PG&E and Edison.

Even though this Itron data plugs a pretty large data gap for us, there are issues with it. Their systems were installed in the early part of the CSI, so there's some kind of vintaging effect going there. The more significant issue is that this production data is only going to be collected until 2016. And I believe that has to do with issues on how the EM&V budget was set up. But this is kind of unfortunate, but at least for the time being we have some kind of -- and there's a frequency pull-out by county for PG&E and Edison, by the number of systems.

You know, you can see some counties have less than 10 or 5 systems, so there is a question just how much we can generalized from this source. But for the time being, this is the best source that we have identified for meter data. We are planning on using this for the time being.

And, let's see, last week, at the Commission Business meeting, we had approval for a contract to update our end-use load shapes, and there is a carve out in that contract for improved PV shapes. And it also will look at other forms of DG technologies, too, so it's not just linked to PV. But it's going to take some time for that work to get completed and the data to kind of flow back to us.

Now, I want to switch gears a little bit and talk about changes we want to make to how we forecast PV. First, to give a little background on how we actually do the forecast. Essentially, we have usage data organized by the different climate zones, forecast zones. The source for these datasets, for that data comes from our Residential Survey, outputs from our forecast models, and load shape data from the IOUs.

Essentially, we have the usage data, we overlay the PV generation data and go through a series of bill savings calculations. In prior IEPRs we used average sector rates. But as of the 2015 IEPR, we've moved to using actual retail rates. And so, we're trying to account for the effect of the higher tiers. We also account for the net metering calculation.

And then, there's a stream of payments that we factor, such as the initial outlay of the system cost, any tax credits and rebates. Which there is a little bit of rebates around for some of the POUs, but at least for the IOUs it's been exhausted.

And our proposal for the 2017 IEPR is to move away from just a single average customer and try to add more customer profiles. And the profiles would be classified by their annual usage, so kind of the low-, medium- and high-usage customers.

You know, it's difficult to try to represent an entire forecast zone with just one profile. So, we're hoping that by adding more profiles we'll improve how we capture adoption from the different customer groups.

And here's a table showing the number of profiles we have right now and what we hope to move to. The profiles, again, are a function of the number of climate zones, and for each climate zone we have two usage types.

So, one is for homes with electric space heating, gas heating. The reason we want to control for that is, again, since we're using actual retail rates there, you have to factor in your baseline allowance, which is a function of season and type of space heating you have. So, we just wanted to control for that.

Again, the more disaggregation we have for the forecast, then our data needs go up correspondingly. We will need more profiles to capture even smaller areas.

So, other changes we want to make. Right now, we're still assuming that the systems are host-owned. But the common form of ownership right now is to lease the system. And we understand in the future that may turn to loans just because of how system costs are coming down. So, we also want to have the ability to model loans, as well.

We used the payback period as the metric to estimate adoption. The payback period that we calculate from the bill savings analysis, that I mentioned earlier, is an input to our market share curve and then we apply a classic Bass diffusion curve to trace out the adoption over time.

And we've had some conversations with utility staff about using payback period. And, you know, when you have leases that have no money down and, basically, you're saving on your utility bill from day one, maybe payback is not the right metric to use. There are other metrics that we're thinking of using. There's bill savings. And then, in general, I think we have agreement with the utilities that we need more research in this area.

That's one of the reasons why we asked Ben Sigrin to come by for his presentation. They've done a lot of work in looking at how customers base their adoption decisions. He's done some surveys in San Diego County, looking at how customers respond to the decision to adopt PV, based on different metrics.

So, we're hoping to collaborate with them and see what we can take away from their approach and incorporate into our framework.

So, we talked about PV in the residential sector, but there are other updates that we are planning to do for the 2017 IEPR. Similar to our desire to have more meter-based production profiles for PV, we'd like to have metered production profiles from non-PV technologies.

We're trying to update an NDA with the PUC to receive production data from their self-generation relay program. This would give us shapes for CHP, fuel cells, energy storage. And I may have left off a few other technologies there.

We're also looking to update our commercial sector building load shape data. Right now, we're using data from our older CEUS Survey. One of the reasons we wanted to do this update is that the CEUS was kind of -- was done a long time ago and so there was a need to do an update.

And we also wanted to look at energy storage. And one of the use cases for the storage for nonresidential customers is savings on the demand charges. And, you know, demand charges are based on 50-minute maximum bid in the course of a month. And since we only have hourly shape, that kind of prevents us from looking at this one. And that's one of the reasons to adapt storage.

So, we are requesting sub-hourly load shape data. We've had conversations with the three IOUs and SMUD. So far, we're still trying to come to an agreement on our request. Once we settle that, we'll make the changes to the form's instructions and make the data request.

The third point here, we'd like to have a more flexible and modular framework for conducting the forecast. You know, there's a number of things on the horizon that will make forecasting DG in the longer term very, very challenging. There's issues about zero net energy homes, their rollout of time-of-use rates, and even within that how these time-of-use periods will look like.

We normally think of a peak to be between noon to 6:00. But, you know, there are proposals that may look at 4:00 p.m. to 9:00 p.m., and maybe not worry so much about the summer as more on the shoulder months. Even overlaying that, you know, your NIM compensation may have a time-of-use component, as well.

So, there are a lot of these issues that we'd like to be able to handle and run sensitivity type runs on it. So, that's another area that we're involved in.

Longer term, we have a new CEUS survey out. And as I mentioned earlier, about the load shape contract. Once data starts coming from there, we'd like to integrate those results into our approach.

Earlier, we talked about how important it is to collect interconnection data and have access to good production profiles for the different DG technologies. The Commission is involved in revamping their data collection rulemaking. DG will be a component of that.

There's a lot of things in motion, so I'm not going to go too much into it. But I believe there will be a workshop later this summer on this, so I just want to kind of leave that out there.

And we're also thinking about -- we have a proposal to try to get NREL on board, to collaborate with them and get their expertise in modeling DG adoption.

This is it for my presentation, so I'll take any questions.

CHAIR WEISENMILLER: Yeah, I actually have a lot. I decided to hold off.

MR. GAUTAM: Okay.

CHAIR WEISENMILLER: You may want to just flip back. Because one of the things whether interrupt you slide by slide, or let you get to the end. I ultimately decided to wait until the end.

MR. GAUTAM: All right.

CHAIR WEISENMILLER: The first thing is do you have a good -- and let me start out by saying I think you've done a marvelous job here. You know, I think one of the things that really emerged last year as a big issue was photovoltaic growth. You know, and it really was having, starting to have a really perceptible impact.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And so, as we drill down and try to get out in front of the changes on the forecast.

So, the first question is do you have a - you go back and forth about photovoltaics and residential. So, again, how important is the residential market relative to commercial and industrial, and how well is our forecast focused on across-the-board?

MR. GAUTAM: Well, in terms of additions, we see more adoption in the residential sector but --

CHAIR WEISENMILLER: By number or megawatts?

MR. GAUTAM: By number. But by megawatts --

CHAIR WEISENMILLER: Of energy, yeah.

MR. GAUTAM: I think, if I have it right, the nonres sec is still pretty substantial by capacity. I believe the split is something like 60/40 residential. So, even by number of installations you have less systems from the nonres. But they do have larger systems, so they do --

CHAIR WEISENMILLER: Yeah, I'm just assuming, if you did some sort of cumulative frequency distribution, you know, the 10-megawatt or whatever CSI programs, if they swamp a lot of the lot residential in terms of impacts. So, I want to make sure that, you know, again, as we go through trying to do the model development we don't lose sight of where the money is. You know, where the big impacts are.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Another observation or question was, you know, you talk a lot about the IOUs. Certainly, this has got to be a big issue for the POUs. You talk a lot about SMUD, but under the 350 and the IRP legislation, you know, we're responsible to work with POUs above a certain size in the IRP context. And these issues are certainly IRP context type of issues.

And so, we need to figure out a way to engage more broadly with the POUs. And I'm sure the trade associations, NCPA and CMUA would be happy to talk to us. But certainly, again, we have a statutory responsibility to deal with POUs above a certain size. And so, we need to really be engaging with all of them in that bucket as we go forward on these discussions.

And part of my reason for really pushing that is that, you know, one of your questions on how to struggle with rate design -- and again, Picker and I both channel each other pretty effectively. But, you know, the bottom line is the PUC is going to time-of-use rates. And, you know, that's certainly where the next bounce on net metering goes and will interact with that.

But, you know, as you try to do your forecasting, there is a natural laboratory where, obviously, SMUD's there already. And as you start thinking about rate differences, you know, POUs have different rates. Certainly, commercial/industrial customers have unbundled rates, again different levels. So, there is a natural laboratory, as you think about the rate impacts, to look across different customer classes for particular IOUs, and to cross-compare the IOUs and POUs.

And, you know, it's probably incredibly complicated to even think about. But in terms of trying to make some sense out of the impacts of higher or lower rates, or different rate designs, you know, the good or bad news is that there is a laboratory within the State already running those experiments that you should be able to -- if you can get the data, you know, you should be able to make some progress getting out in front of those issues.

MR. GAUTAM: Okay.

CHAIR WEISENMILLER: Okay, the other observation is that in terms of the -- you talk a lot about -- again, on a forecasting connection to, you know, the cost effectiveness of the least types of stuff.

And I was going to point you to, Severin's done a lot of analysis. You're probably well aware of it. And I was at a power conference two years ago, and it was a panel, whatever, and they asked me to basically react to the papers. But, you know, and certainly they -- he dug in pretty deeply into the question of where's the PV gone, how do you unbundle that by census tract to income, and what were the income distributions of people? And, you know, not surprisingly, higher income people are the ones buying the PV systems, as opposed to lower income, was at least his conclusion at that time. I guess it's sort of a debate people go back and forth on.

And there were some papers on the rate design impacts. You know, eventually going through and saying here's a POU. Here's an IOU group, very similar demographics, but obviously much different rates and much different rate design.

So, again, some pretty interesting power conference papers on that. And I really pushed Severin to start thinking more about leases. Since as you indicated, at the time most of the sales were really lease or PVA.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: It's probably shifting now more to finance-alone. But again, it sort of is he's trying to untangle the sort of economic drivers of peoples' decisions.

That, you know, again, that seems to be a resource to really connect into.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And, you know, particularly as we go forward trying to make sense out of again what's -- we know things are changing very fast. The costs are coming down. We know the tax credit aspects. We know the financing structure of the industry. The rate design. There's a whole bunch of factors hitting fast. And so, your forecasts go past where those changes are coming into place.

So, we need to figure out how to untangle what some of those changes will mean.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And on the NDA, certainly if there's an issue there, let me know. We can try to move that at a higher level.

MR. GAUTAM: Okay.

CHAIR WEISENMILLER: Again, I want to point out that one of -- obviously, one of the things we try to do is connect to the PUC. And Michael Picker is really driving on the area of distribution planning. He and I are coordinating with New York. Both he with, obviously, the POC and myself more with NYSERTA.

So, you know, it's a pretty well-connected activity going on there. And so, just as we -- I need to make sure that what you're doing is going to be useful in the PUC context that, certainly at the same time, if there are things that the PUC can do to facilitate your research, I need to know that.

MR. GAUTAM: Okay.

CHAIR WEISENMILLER: So we can do those connections.

But certainly, if there's a way -- you know, again, I think on the interconnection stuff we really need to be thinking on the data collection part about, you know, all the POUs in the IRP context. And then you need, again, to be thinking about how you untangle the different climate rate stuff for those and how that can help your research.

MR. GAUTAM: Yeah, plenty, I think, to keep me busy.

CHAIR WEISENMILLER: Oh, yeah. Yeah.

Okay, great, thanks again. Thanks again for your hard work in this area.

MR. GAUTAM: Thanks.

MR. GARCIA: All right, thank you, Asish.

Next up we have Melanie McCutchan, from PG&E, with their take on photovoltaic adoption.

MS. MC CUTCHAN: Good morning, Commissioners Douglas and Weisenmiller. And good morning to everybody participating here. My name is Melanie McCutchan. I'm with PG&E's Policy and Strategy Team that's focused on distributed generation.

And one of the things our team does is we help PG&E incorporate retail solar more accurately, more appropriately into our planning.

And I want to first thank the Commission, and Mr. Gautam, and Mr. Kavalec and Garcia for the opportunity to present to you today. And I think I also want to say I very much appreciate the CEC staff, the other IOUs' collaboration around really trying to navigate what is a difficult task in terms of anticipating a very dynamic PV market, with a lot of policy and market uncertainty associated with it.

And I think, I appreciated, I just glanced at Mr. Sigrin, from NREL's first slide, and it says that "predicting adoption is hard". So, I don't mean to steal your punchline there, but I think it's a really good thing to keep in mind. But we have to do as good a job as we can because it has significant implications for planning.

So, the four main points I wanted to cover is that I don't think it's a mystery to anybody that we're seeing a lot of behind-the-meter PV adoption and it's already having material impacts on system load.

Given the growth in this area, PG&E has invested in tools to improve our incorporation of solar into our load forecasting and system planning. And we think this is important and we've identified some areas, as has Ashish, Mr. Gautam went over as well, where there's some gaps in understanding in PV adoption patterns and how retail solar impacts hourly load.

And so, one of the key things we're hoping will come out of this workshop is more recognition that there needs to be more resources focused on this area. I think we've done a lot as a State to really better understand energy efficiency and the impacts on load, demand response. But because PV adoption has kind of come so quickly, we're not really at a comparable level in terms of tools and information to help inform adoption forecasting and generation forecasting.

So, wanted to just demonstrate how quickly solar has been growing in PG&E's service area. It's been growing at a compound annual growth rate of 35 percent over the last five years. And we're also seeing it has been clustered, as Commissioner Weisenmiller mentioned. You know, it's generally been higher income areas and, of course, mostly single-family homeowners are the folks who have been able to adopt. So, you see a lot of clustering, as you can see on this map. And what this map is showing is the interconnected PV capacity by feeder in PG&E's service area.

So, as I mentioned, I think the growth in retail solar has really exceeded expectations and we're seeing continued significant variations in projections. And, you know, I don't want to sort of point to CEC, particularly, in terms of having underestimated PV growth. It's all analysts, virtually, you know, were on board with that. And I think it's just been a very rapid sort of development. And we're seeing that technologies in general tend to be adopted more quickly due to all the marketing and communication channels that we have currently, in the 21st Century here.

So, I just wanted to demonstrate sort of the scale of the impact on future anticipated load that the kind of changing in projections has had.

So, what you're looking at here is, in this sort of dashed orange line is the forecast from 2011, for the 2011 IEPR, the mid case, the mid case from 2013, and then the most recent update. And you can see that the yellow represents estimated generation based on actual interconnected capacity.

And we're seeing that, you know, the CEC has revised the forecast and we've appreciated all the effort that's gone into that. And we wanted to also demonstrate that when we're looking at it, what industry analysts are forecasting, there is continued variation.

And so, I think it really is -- even if predicting adoption is hard, if we can sort of limit the bounds of that uncertainty, I think that would help in our system plan and make sure we're doing efficient system planning.

So, I wanted to give sort of a high level overview of how PG&E approaches forecasting PV. So, we start, and this is a pretty common standard approach, very similar to what the CEC does, and what NREL does in their solar DS and new DGEN model.

But we start by estimating a market potential for retail PV. We look at how much viable surface area there is for PV in terms of technical potential. And then we look at current and future PV costs, and bill savings associated with being a PV customer, and figure out how many folks would be in the money, and for how many folks for whom this would be a compelling value proposition.

And then, we account for other constraints on adoption. Home ownership is, you know, a really important factor in terms of folks being able to invest in PV. It's difficult to envision how, in the near term at least, the sort of property owner/tenant relationship could be adjusted to allow for more PV adoption in the rental sector. So, that's something we're certainly keeping an eye on.

And then we use a Bass diffusion modeling framework to estimate the rate of adoption. You guys are probably familiar with the kind of technology adoption terms, like early adopters, majority. And then, sort of essentially most technologies follow this kind of S curve shape in adoption.

And so, we look at literature, and as does CEC, and look at and kind of calibrate to historical adoption and try and figure out how quickly the uptake is going to take place.

And then I think a really key point in this number three is that we have to account for -- there is significant policy and market uncertainty in terms of solar as a value proposition, as an attractive product going forward. And so, we develop a distribution of possible outcome and incorporate uncertainty into our planning.

And then on number four here, we, as part of the Distribution Resources Plan that we submitted in July of last year, we were required to allocate our forecast down to a feeder level to give our distribution planners some tools to help them better assess how retail PV is going to affect our distribution system.

And in order to do that we did a logistic regression, which is basically a predictive tool to try to figure out who would adopt, be likely to adopt solar. We looked at folks' usage, their income, whether or not they're a homeowner, and some other factors, their credit score. And looked at historical adoption and were able to figure out what are some of the main drivers of adoption. And then, figure out who's most likely to adopt within our territory.

And that's enabled us to sort of anticipate where we might need to make some retail PV-enabling investments, like to accommodate two-way power flow. And it's given our planners a tool for seeing how retail solar could impact distribution assets.

So, a key point that Mr. Gautam hit on is that it's really important to understand how solar is going to affect the sort of load at the meter that we need to plan for. And in order to get a better handle on this, PG&E's developed some solar profiles using CSI data, and our interconnection date, and NREL's PVWatts Tool.

And our meteorology team is actually in the process right now of developing more geographically granular estimates all the way down to the distribution planning area.

And then, also, trying to get some sense of uncertainty bounce. And, you know, I think you have to think about planning criteria if you want to make sure that you have the assets necessary to continue to serve customers, that you're planning to a reasonable element of uncertainty. So, that's another thing that we're making sure that we're incorporating.

And then this fourth bullet here, it hits on the fact that you can't just look at folks' load before they became solar customers and then put a generation profile over that in order to understand what they're going to need for the grid.

And just for some context, in case folks aren't aware, we -- most of the IOUs don't have generation data for their PV systems interconnected in our territory. So, when we're trying to figure out what was the load that we need to serve, we have to model, essentially, what a solar customer's needs are going to be both in terms of interconnected, current interconnected solar customers, but then looking out into the future.

So, you know, we may see that in initial looks we're seeing that the consumption patterns do change after folks become solar customers.

And, actually, Commissioner McAllister's dissertation is one of the few bodies of literature that's been done on this. And so, it's an area that could use more attention and build off that work that was done.

And then, another thing that is important is that when we do our demand forecasting and planning we plan to, for example, sometimes a 1-in-10 heat event, or to account for how the weather affects demand, of course. And one thing we're finding is that temperature really affects solar production. The panel efficiency goes down dramatically after a certain temperature. And so having better information on that, on how to model that would help us understand what's going on in our system.

And what I'm calling, now, the solar igloo thing, bears some explanation. But it's basically a month hour system, a generation profile for a typical retail PV system in PG&E's service area. And what you're looking at here -- I guess I'll have to just point. So, we're going to talk a lot more, I think, later in the day about how our system peak is shifting. And retail solar is one factor in why that's happening.

And I think I mentioned that, you know, solar is already having a meaningful impact on our load. And we believe it's playing a factor in a shifting of our load, our system peak and the peak month from hour ending 16, or 4:00 p.m., to hour ending 18 or 6:00 p.m., just based on the about 2,000 megawatts of solar we have installed right now.

And going forward, the key thing to see here is that the incremental contribution to reducing system peak from solar is going to go down as the sort of net peak goes later into the day, right. So, solar is producing at about almost 40 percent at hour ending 18, or 6:00 p.m. At hour ending 20, or 8:00 p.m., solar is producing only at about one percent. So, it's really important to get that incorporated accurately in our planning.

And so I mentioned that there's some gaps in tools and information. And then, there are some inherent challenges in doing this kind of forecasting. But I wanted to hit on one that I thought was important. And that is that, and Asish Gautam mentioned it earlier, but a key part of the modeling is to really understand how customers are going to respond to the cost-effective -- the value proposition of the cost effectiveness of solar.

And what I wanted to show here is -- these are images from the documentation that NREL put together for their model. And there's been some shifting and thinking in terms of how folks may respond to certain levels of cost effectiveness for solar.

So, what you're looking at here is on the X axes -- axis, rather, on both graphs, you're looking at the percent of market share that you'd expect given -- I'm sorry, on the Y axis. The share of market share you'd expect for a given payback or cost effectiveness on the X axis. And the curves you're seeing there, in the A-labeled graph, are showing that you really need very high -- or low payback times in order to see a lot of adoption.

And these studies were mostly based on a study of electric heat pumps done in 1982. And, you know, with some kind of calibration after that. But, you know, really, that's just not a good representation of where solar decision making of house -- solar decision making is being made.

So, Mr. Sigrin, who will be presenting after me, has done some work, as Mr. Gautam mentioned, in San Diego County, doing a survey of both folks who have adopted solar and how have not adopted solar. And has introduced a potential, and I know this is not a final, I think, curve, but a potential new look at how customers respond to cost effectiveness.

So in graph B what you're looking at is, on that light blue line, is the result of the study and what that would indicate about how much folks would adopt, what portion of the population would adopt, given a certain level of payback. And you can see that it would -- using that curve, you would predict a lot more adoption.

So, talked about -- I just want to identify a couple more gaps. So, we talked about customer responsiveness to solar cost effectiveness. We also talked about the consumption patterns after solar adoption, so how do folks' loads change after they go solar.

And then the third bullet was hit on by Mr. Gautam. That, you know, there just are some real uncertainties around future rate design and how that will impact solar economics. And so, it's important that we are open to really incorporating uncertainty into our planning decisions.

And I will end it there and let other presenters come on. Any questions?

CHAIR WEISENMILLER: Yeah, so I'll ask you some of the same questions I asked staff. So, you know, first is the proverbial, have you thought in terms of any stratified frequency -- cumulative frequency distribution, again, how much the impacts on PG&E's systems are coming from commercial/industrial, versus residential?

MS. MC CUTCHAN: Well, you know, I think it depends what level of the system you're looking at, right. So, if you have one -- if you're looking at a very granular level, like a feeder, and you have one big nonresidential system it can have a quite a big impact.

In terms of scale, the numbers that Mr. Gautam mentioned, about 60/40 --

CHAIR WEISENMILLER: Right.

MS. MC CUTCHAN: -- res/nonres are about right for PG&E. And so in terms of -- and that's installed capacity so, yeah.

CHAIR WEISENMILLER: Yeah. Well, the other question is similar to -- well, actually, I think you and I have had this conversation before. So, obviously, as solar costs have come down, installations have gone up. You know, and at the same time most of the models look at it in terms of cost effectiveness.

And at the same time, most of the installations so far have been a lease or a PPA. And so, in a way things are much more determined by FICO score than cost of -- you know, presumably, they try to target the marketing to high FICO scores and go in that direction, and that sort of arrangement, zero down, et cetera. You know, it sort of flips the logic, it would strike me, from a simple cost effectiveness calculation.

So, I mean, you certainly have taken it down to the next step, into customer class and targets. But again, how do you go from an economic cost effectiveness to something that reflects more the variety of packages being offered to consumers?

MS. MC CUTCHAN: I think one strategy is to basically have different curves depending on, you know, if somebody's owning it themselves, going through a loan, going through a lease.

CHAIR WEISENMILLER: Yeah.

MS. MC CUTCHAN: So you might want to study -- you know, if NREL is able to go forward and do some more work on this, that might be a consideration to actually do different market curves for each type of arrangement.

CHAIR WEISENMILLER: I mean we have to -- the other question is obviously your CI ratio are unbundled right now, they've been unbundled for years. So, in terms of how far do you get into rate design in this analysis, as opposed to some silly this is the average rate?

MS. MC CUTCHAN: So, we've found that looking at average rates just doesn't work.

CHAIR WEISENMILLER: That's what I assume, yeah.

MS. MC CUTCHAN: And so, we segment our customers by tariff and by ten usage classes for residential.

CHAIR WEISENMILLER: Yeah, how about CI?

MS. MC CUTCHAN: CI just by tariff.

CHAIR WEISENMILLER: Okay.

MS. MC CUTCHAN: Yeah.

CHAIR WEISENMILLER: And do you have a sense of how the -- you know, you pointed to various expert groups, you know, who do forecasts, which are obviously much higher than staff. Do you have a sense of what their methodology is?

MS. MC CUTCHAN: It’s very similar. But rather than using this kind of payback approach they use a benefit cost ratio, which basically captures bill savings. So, you know, if my average retail rate is 17, 18 cents in PG&E’s area or so, and I can go out and get a lease for 15 cents, then you’re saving quite a bit of money and there’s -- that’s really -- can be translated into a levelized benefit cost ratio that is actually what we use in terms of our forecasting, as well.

CHAIR WEISENMILLER: Okay. I mean, obviously, PG&E now offers a solar option to its customers. Have you done any forecasting on what sort of uptake you expect from that?

MS. MC CUTCHAN: I haven’t, personally. Another team may be working on that at PG&E.

CHAIR WEISENMILLER: Yeah, that may be something which, again, I think staff would probably be very interested in those sort of studies, too. As, you know, he tries to sort of incorporate all solar, not just -- Basically, and I think the other thing it would be good to have some sense on is, as you indicated, this is really a huge area. Everyone's scrambling to step up in terms of the research side and the modeling side.

And I guess it would be good to get, from PG&E, some sense of research priorities in this area. And since, frankly, you can be more nimble responding, than we can, to get a sense of where you're going to spend your research dollars and those methodological improvements.

MS. MC CUTCHAN: Well, that's a good segue for a point I kind of forgot to make, but really wanted to make sure we hit on. And that is that, and Chairman Weisenmiller, you mentioned you were perhaps willing to connect with the CPUC in terms of more collaboration on developing better tools and information.

And, you know, we do still have quite a bit of measurement and evaluation money left through the CSI program. The last time that the CSI program did an impact evaluation was in 2010. So, it's really time to leverage some of the Itron data that Mr. Gautam pointed out and do some more studies to help us plan for a future that has a lot more solar in it.

CHAIR WEISENMILLER: Yeah, that would be good. I think the other thing I would point out is President Picker's vision on, you know, essentially how we tie things together is that for your distribution resource planning to use assumptions adopted by the Energy Commission on loads and, you know, the various preferred technologies.

And so, obviously, that's one of the reasons we're scrambling on upping our game here, both in terms of the methodology and the level of disaggregation.

MS. MC CUTCHAN: And I would also emphasize that, you know, we -- a lot of our planning relies on statewide forecasts.

CHAIR WEISENMILLER: Right.

MS. MC CUTCHAN: And so we are absolutely, you know, committed to using the CEC's forecast on a statewide level and for our planning. And, you know, we'll only make adjustments if we see it necessary.

CHAIR WEISENMILLER: Yeah, but again the bottom line message is President -- when you go into President Picker and say this area needs X, he wants to know if we agree on that.

MS. MC CUTCHAN: Right.

CHAIR WEISENMILLER: And he wants you ultimately to be using what we're adopting. So that means that's one of the drivers for us on a much more granular forecast.

MS. MC CUTCHAN: Right. Great, and we are working very closely with CEC staff and other IOUs on this, and so look forward to continuing to do so.

CHAIR WEISENMILLER: Okay, great.

COMMISSIONER MC ALLISTER: Great. Well, a couple of questions. So, thanks for the presentation that was great. I really congratulate you on your impeccable references.

(Laughter)

COMMISSIONER MC ALLISTER: But a couple of questions just on -- well, really on a personal note, I guess it is difficult to do this kind of analysis. And, you know, keeping track of the marketplace is very difficult. It's way, you know, it's way different now than it was four or five years ago. And we'll get, you know, we'll evolve in ways that maybe we don't exactly know. And I think your research is really key to kind of anticipating some of that and getting good numbers, so we can plan. And granular is good and I think we all are in agreement where the forecast is going with all this. So, I think the way you've laid it out is really great.

I guess, you know, and I just very much agree with the rates discussion. That the rate, you know, what the consumer sees is really going to be key to how this develops. And, you know, my own experience is that consumers really listen to what the contractors say and they make kind of an overall value proposition judgment. But, really, marginal rates and sort of the details are things that don't really -- they're not really tuned in enough to that to use, you know, the details. But really, it's an overall value proposition.

And as solar gets lower and lower in cost, you know, my sense is it's becoming more commoditized and it's less -- it's sort of less about the financing and the cost effectiveness sort of details than it is just like, hey, this isn't as big a deal as maybe it was five years ago.

I guess I'm wondering -- so, we saw the -- you know, starting out the pioneers bought their systems, put them on their roofs. And then it migrated over to, you know, 70, 80 percent finance of some sort. You know, third party, leases, or whatever.

And now, I'm wondering if that trend is continuing or if we're seeing an evolution back towards ownership?

MS. MC CUTCHAN: I think you're right that as the price of solar comes down, the financing becomes the less critical piece to making this viable for folks. So, you know, if you can by a 3-kilowatt system for $8,000, $9,000 versus, you know, $25,000 or $30,000 when the CSI program wasn't in place, the financing becomes less important of a factor.

And we are seeing more host-owned and, you know, home equity financed solar.

COMMISSIONER MC ALLISTER: Do you have data about that? I mean, is that being tracked?

MS. MC CUTCHAN: It's being tracked by Green Tech Media's research, or DTM research. There's a study that I can share with you that -- or, it might be a pay-for study.

COMMISSIONER MC ALLISTER: Yeah, okay.

MS. MC CUTCHAN: But I can point you to it.

COMMISSIONER MC ALLISTER: So I'm wondering, I was in late, so sorry about that. But did you talk about sort of the trends along those lines? In terms of data accessibility, I guess who's tracking what? I mean, I know that's been an ongoing issue.

MR. GAUTAM: Yeah. So, I believe the -- in the IEPR we're trying to get into what -- if the systems were host-owned or leased. And the new interconnection data set is, is trying to continue the efforts. There is data behind that, but I haven't had a chance to kind of cross that --

COMMISSIONER MC ALLISTER: Okay. Melanie, do you know if that field is still being tracked in terms of, you know, post-CSI, if that's still being registered?

MS. MC CUTCHAN: I believe that's a voluntary field and the spot may be a little spotty.

COMMISSIONER MC ALLISTER: Okay. So, I mean, that would obviously be helpful for this kind of market analysis.

So, let's see, you know, I lean on energy efficiency but, obviously, kind of very interested in the solar side of this as well. So, there are increasingly people that have solar, but that also want to still pay attention to their consumption. Not that everybody wants to get into the details.

Right now, I think, I believe it's very hard to do that. And I'm wondering how, you know, if there's a plan -- or, maybe this is already in place and I just don't know about it. But if, for example, I've got an inverter that shoots production data over to wherever but, you know, it's web. You know, it's on the web and I can access it. And I've got my Smart Meter from PG&E that I've got hooked up to a device that fees out of the web.

And I guess I'm wondering if -- you know, I'd like to be able to combine those things, get a net consumption. Get net consumption with production and get a gross consumption, and then be able to do analysis on that, and that's the only way I can actually look at the performance of my home, right.

I don't want to do all those details. I don't want to be a coder. I don't want to do -- and 99.9 percent of us, I think, are in that same boat.

But I guess it would be great to have that institutionalized and fed into some -- you know, so you could use Green Button, or something of its ilk to sort of say, okay, well, this third party's going to tell me what my investment priorities in my home ought to be going forward.

Do you know about that or can we find out about that?

MS. MC CUTCHAN: Yeah, I'm actually happy to report that PG&E definitely wanted to be responsive to hearing from our customers that they really wanted to be able to combine their generation data with -- their PV generation data with their Smart Meter data to get, like you're saying, a full picture of their consumption.

And we've been working with Enphase and Solar

City, and some of the generation production trackers, providers to work longer term to try to facilitate that.

But we, just this year, have started a pilot project. I believe it was EPIC funded. That allowed us to give our solar customers within the My Energy, kind of Green Button space and where they're able to look at their consumption, actually give them a full picture.

So, we have about 250,000 solar customers in our service area, now. And that pilot project is being rolled out to 10,000 of those customers. So, we'll see. It seems to be going well so far, but I think we'll want to take a closer look at that.

COMMISSIONER MC ALLISTER: Great. I'd love to know more information about that. I think it's a really valuable kind of effort going forward.

CHAIR WEISENMILLER: Yeah, actually, I thought for a moment there you were going to the other question which was -- my impression is the solar companies really are looking more at upselling.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: Their preferred base to storage, at this point. And so, one of the questions is how do we best incorporate that in the forecast.

COMMISSIONER MC ALLISTER: Yeah. Also, on the rate side, again, I mean I think we're seeing the PUC and, you know, obviously we don't all have a crystal ball as to where it's going to go in 2019. But they've made a distinction, now, between the energy that's getting pushed in the grid and the energy that's consumed behind the meter.

And, you know, that's going to make a big economic -- that's going to drive a lot of this stuff going forward. And so, I actually think that's appropriate given a lot of the distribution conversation. But that's a kind of a key variable going forward.

I don't know if the Chair agrees with that, but the rate design I think is really critical.

CHAIR WEISENMILLER: No, I had actually encouraged folks to look a lot at the variation among IOUs and POUs, and among commercial/industrial. There's just so many different rate designs already in California. We can try to get in front of, you know, some of that impact of what's coming.

And, obviously, from an NREL perspective, if you're looking, say, at Hawaii or, you know, New Jersey, again there's sort of that natural laboratory of saying, okay, what's happening with different rate designs around the country.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: Much less within California. And what does that tell us about what time of use, or higher or lower rates, what it would mean.

COMMISSIONER MC ALLISTER: Yeah, I think this business model question about what -- you know, solar has come down so much that I think there's -- even with reformed rates, there's going to be a clear value proposition for somebody who wants to go solar. I mean, within the kind of realm of possibilities that we're looking at now, sort of reasonably.

But the value proposition has been so great now, like up to now that I think the companies, themselves, have kind of had a pretty sweet deal in terms of the amount of margin they can generate and still offer the customer a really good deal.

And I guess I'm wondering -- well, anyway, I think we'll all see how -- you know, on the flip side what does the customer need? You know, we've talking about that, what does the customer need to see in terms of rate of return, you know, payback.

But the flip side of that is what the solar company needs to see for their business model, right. And so, you know, what investors want to see in terms of margin.

And as the whole kind of thing narrows, as I think everybody anticipates with NEM reform and with rate reform, you know, time of use and all that kind of stuff, we'll see, right, who sort of who stays in the market. Who's going to try to upsell more aggressively, less aggressively. How they're going to design systems, you know, what sizing and all that kind of stuff. So, very interesting.

But I, personally, think there's a great value proposition going forward, you know, if what -- you know, in the realm we think is going to happen, actually happens. You know, a lot of good stuff happening in the marketplace.

We want to have that same marketplace dynamic for efficiency, by the way. So, not just storage, but in terms of efficiency. So, you know, we need to get the solar companies back in to selling efficiency.

So, okay, well, that's it for my questions.

MS. MC CUTCHAN: Thank you. No questions? All right, thanks so much for everybody's time.

MR. GARCIA: All right, thank you, Melanie, appreciate that.

Next up we have Ben Sigrin from the National Renewable Energy Laboratory. He has quite a bit of information, so let's get ready to digest this.

MR. SIGRIN: All right, good morning. My name is Ben Sigrin. I'm a staff engineer at NREL. I work out of Golden, Colorado. I'd like to thank the Commission, and the Commissioners, and the audience for allowing me to present today.

So, I'm involved in a variety of modeling and forecasting issues. For PV, generally, but also other distributed energy resources. And we're also involved in a variety of theoretical work. By that I mean understanding consumer behavior, their responsiveness to economics, issues of competition, and pricing, and so on.

So, the topic of my talk today is "Predicting Adoption is Hard". As some of the other presenters have noted this is -- you know, this is not a final problem. We haven't solved it. We're still trying to find the best methods of answering this.

So, I think the question that everyone really wants to know is how much PV is there going to be and where the heck is it going to get deployed.

So, this is a paper I've been working on recently. It's a working paper. And in here we compiled a few published forecasts of distributed PV in the residential sector in California. And we also generated some of our own forecasting techniques.

And the take away here is that even among different types of forecasting there's great, you know, disagreement about how much there's going to be? When first-time adoption will peak? What time that peak will occur and so on.

So, I think this sets the stage that, you know, again, this is not a solved problem. There's a lot of moving pieces, as some of the other speakers have noted.

So, I wanted to first note what I consider four main issues in the field. The first one is that, as some of the speakers have presented, as the Commissioner has noted, there's great heterogeneity in consumer preferences. So, the figure on the right is a national distribution of annual electricity consumption, from DI RECS survey.

And basically, you can see that taking the median or mean of that distribution is unrepresentative of the wide variation in energy consumption. So at least in California, on our tiered rates, if you're on the right-hand, the long tail of that distribution, then the value proposition when you're offsetting at tier three or four, for example, is very different than if you're on the left side of the distribution offsetting, say at tier rate or maybe even a care rate.

So, we really need to be careful to not take just the mean consumer. We have to understand the wide variation in consumption, but other kind of tech and economic characteristics that would define their propensity for adoption.

The second issue is that, this is not true of all models, but some specifications can suffer from what I call a knife's edge. And so, by that I mean you can sort of have an all or nothing response. Either, the breakeven cost of solar is above or below the retail rate, you either get 100 percent adoption immediately, or zero percent.

And, of course, you know, in the real world that's not really true. So, we have to be careful. And especially zero-down financing, leasing in other words, where you can have positive cash flow from year one. This is something to incorporate into your modeling.

The third issue is, as some of the speakers have noted, potentially there's a lot of data requirements here. And, you know, it really depends on the resolution of your model. But the consistency and the formatting of the data can be overwhelming to an analyst.

And then, additionally, some many things are changing so quickly that most of our data needs to be effectively, continuously updated. At the minimum, on an annual basis. But there's many other things, costs, rates, business models, and so on that do need to be accounted for on a sort of real-time basis.

And the fourth issue is that there are many sources of uncertainty in our forecasting. There's uncertainties both in our techno economic characteristics, like what will be the real cost of solar in 2020? What will be the cost of storage in 2020?

Of course, there's also uncertainties in the underlying specification. What is the real response of a consumer, say, to a five-year payback. And so, because of these uncertainties, you know, we often are forced to make a certain decision. We have to come up with a reference scenario. We have to have some expected value.

But at least at NREL and I think a lot of other institutions, we see a great value in scenario analysis where we can try to understand what are potential tipping points? What are costs at which, if they reach a certain cost, that you might get a tipping point in the response?

And so, I think that doing scenario analysis to capture some of that uncertainty, to understand where are the tipping points, as I said, should be considered in all forecasting.

So, I'd like to talk about sort of two general model types that I see in the literature right now. The first is top down modeling. So, top down modeling, by that I mean we're trying to represent population-wide demand or population-wide summary statistics. So, these are generally econometric or regression type of models. So, we might say, you know, the average income in track A.

And of course an advantage of these types of models is tractability. There are many published sources of data where we can get ready access to summary statistics, you know, say at the tract or the county level.

But the disadvantage, as we've noted, is the inflexibility to consider new technologies, new business models, other sort of evolving economic drivers. There's also a perennial concern for over fitting and whether these top down models can really incorporate sources of uncertainty in their forecasting.

So, of course, the opposite of top down is bottoms up. So, bottoms up modeling, these are where we're trying to represent individual level demand or individual level characteristics. Or, if not at the individual level, then at a statistically representative cutoff.

So, these are generally engineering models. And an advantage of these is a flexibility of the specification. Basically, we can always add another module. We can have limitless detail of the features that we consider important in a model.

So, the Commission has talked about third-party ownership. That's something that you could incorporate in a bottoms up model without too much work.

And then, of course, the disadvantage, as I noted, is that these types of models can be quite data and computationally expensive. And so, that needs to be kept in mind given limited staff resources.

So, let me give one example of a top down model. So, this is a model that my colleague, Carolyn Davidson, estimated in 2014. So, this study combined several types of geospatial information, population demographics, solar radiance, et cetera, at the tracked level to understand what subsets of geospatial information were the best predictors of PV adoption. So, essentially, the median income in that county, the median homeownership rate, et cetera.

And we also used a LEAPS approach, where we are sequentially adding variables to the model to understand which combination of variables adds the most predictive value to the model.

And so you can see some of those most predictive variables here were mortgage or homeownership rates, the home size, such as the number of bedrooms, electric vehicle ownership. And this model performed fairly well. We got up to about 50 percent R squared. But there's limits to what you can do with aggregate statistics.

So, let me give another example of a bottoms up model. So, as has been mentioned before, NREL has been performing distributed PV forecasting since around 2008. Our initial model was called Solar DS. This was a bottoms up market penetration model. And we simulate household, so residential and commercial decision making through what I call a binned approach. So, some attempt at understanding heterogeneity, say a bin of high-consuming households, medium consuming, low consuming, et cetera.

And we also had specific engineering submodules there for the PV performance, its temporal generation profile and also the financial performance, doing a discounted cash flow model. As has been noted earlier, that model draws upon vast theory to understand how customer adoption could be simulated over time.

So, I want to talk about one of the new frontiers that I consider in diffusion modeling, and these are agent-based models. I assume that parts of the audience here are familiar with these. So, an emerging specification are HM-based models. These are extremely bottoms up models of individual consumer behavior.

So, the building blocks of an agent-based model are we have a theory driven specification. We defined, you know, micro drivers of behavior, such as I would adopt if it was economically sound. I would adopt if others in my peer network had also adopted or at least that would influence me.

These manifest themselves in specific behavior rules. How much response to the peer effect? How much response to the economic effect? And then, those can be simulated over time, simulated both over time and over geographies.

So, agent-based models, in my opinion, are a useful method for simulating DG adoption because these agents can explicitly represent the underlying population heterogeneity. They can respond to both economic drivers, stimulated events such as a high summer electricity bill. And they can also response to peer effects, non-economic drivers, such as the influence of my neighbors adopting.

So, ultimately, another great advantage of these are it offers a rich opportunity for model calibration and cross-validation. In other words, we can use prior historical data to calibrate responses and uncover rules of behavior.

So, let me give two examples of successful agent-based models, currently. On the left, this is an empirical agent-based model for the Austin, Texas metro area. It was performed by Dr. Varun Rai. He was my graduate advisor at the University of Texas.

So, this is sort of the extreme of what agent-based models can be. They have surveyor data for each building and each household in the Austin metro area. For each of those buildings they're trying to uncover the set of attributes that they can at that resolution.

So, some of the factors in their model were attitudes of the households, perceived uncertainty of the technology, peer effects as I've mentioned, and also economic benefits.

On the right, this is a theoretical model that I've been working on with Dr. Adam Henry, from the University of Arizona, for the Sacramento Region. And in here we're trying to understand what the optimal allocation of rebates might be. Basically, how can you maximize diffusion given a set investment budget for the rebate?

So, as has been noted earlier, if we assume some amount of segregation in social systems, in other words some neighborhoods are richer than others, some are poorer, and that the propensity for adoption is dependent, at least some part, on socio demographics, then inequitable distribution of rebates is an inevitable consequence of that type of social segregation.

Okay, so I'd like to spend the rest of my time talking about our current approach. So, as I mentioned earlier, Solar DS was our original model. We've since upgraded this in 2013 and '14 to the model called dSolar. DGEN actually is our general distributed energy Resource Model.

So, this is a model that uses both top down approaches and bottoms up principles. As I said, it draws upon many of the principles of Solar DS. But some of the new features, as I've mentioned, are a foundation in spatial data. And so by that I mean, you can see in the figure on the right, we start with sort of real world features, urban development, population, solar resource, et cetera. Each of these can be coerced into geospatial layer.

And then, the agents are embedded in that ecosystem. They can understand, you know, how many adopters are around me, what incentives are available in my area. It just makes a very coherent framework for modeling agents.

And then, also, as I mentioned earlier, there's sort of this tradeoff of models' precision versus the amount of data required to calibrate it.

And so what we do currently are statistically representative agents. We cannot capture the full set of attributes for every building in the U.S. That's obviously not feasible. But what we can do are cluster them, in a sense, to say what are statistically representative agents. Agents that represent, say, 100 households like me in the community that might all have similar attributes, like a high level of consumption, a large home, a high level of environmental concern, things like that. So, that's our current method for dealing with the heterogeneity issue.

So, I think this concept has been described earlier this morning, but one of the ways that we think about this problem is a concentrix -- sorry, a series of concentric circles, estimating the different potential levels in a market.

So, resource potential at the far left. How much theoretical irradiance falls on the earth every day. Technical potential, what is the total usable rooftop area in a region. What would be other siting constraints, like shading, like roof quality, et cetera.

Economic potential, given the set of agents that could feasibly adopt, how many of them could do so at an economic advantage.

And then, finally, at the far right, market potential given the set of agents that could both technically adopt and do so at a profit, how many will actually adopt and what will be their patterns of adoption over time.

So, you know, I sort of flipped back and forth between the micro and the macro here. But I do want to take a step back and say I think that getting the big things right is also very important. So, estimating sort of our macroeconomic factors, like building counts in a territory, addressable rooftop space, addressable load. These should all be considered sort of a zero order of priority where, if we get those things wrong, then everything else downstream of it is going to be wrong in the model, too. And probably the error’s going to propagate and get larger.

So, we spent a lot of time trying to get these macro factors right. One of the studies that we did earlier this year, we got LIDAR satellite data, where we were able to image something like 130 cities in the

U.S., and understand the shading tilt azimuth and rooftop area for each building, each panel -- I'm sorry, roof polygon in that area. And so, those helped to inform, from a data-driven process, the usable rooftop area.

So, I think that one of the trends that we see is that increasingly these types of estimates are based on information of either real buildings, a census of real buildings, or at least a sample of the buildings in the region.

So, next economic potential. I think this has been talked a lot about today. So, what I want to emphasize is that the economic factors are important. We can't just use, say, the mean cost of electricity because some consumers are offsetting in a much higher rate, some at a lower rate. And we also need to understand hourly effects like as we move to time-in-use pricing the hourly effects will be more important, demand charges, fixed charges, et cetera.

So, basically, for each agent in our model we're going to do a discounted cash flow analysis that incorporates the retail rate structure, the project technology costs, whether they can apply for any incentives. And then, as we've talked about a lot today, available financing terms, whether a system is bought or leased, and at what rate, at what tenure.

So again, particularly in California, at least right now with our tiered retail rate structures, PV economics are very dependent on energy consumption levels. So, optimal system design is complex. It's going to get more complex with time of use rates and/or, you know, as storage starts to play a big role in the retail space.

So, finally, market potential. You know, simulating the customer decisions remains the most essential, yet uncertain aspect of diffusion modeling. I mean, ultimately, we're trying to predict human psychology here. And we can do a lot of surveys, we can have different estimates, but at the end of the day human psychology is human psychology. It's not an engineered system.

So, I think Melanie showed a graphic like this. One way that we think about this is payback time on the X axis, what percentage of customers would respond if exposed to a certain payback time.

And then I think, also, thinking about other metrics is very relevant. I'm working on a paper related to that. But monthly bill savings we see is starting to eclipse payback period as the main metric that consumers use to evaluate that decision. I think that's driven partially by leasing. It makes the most sense to evaluate a lease system in terms of how much am I going to save per month.

But also, I think that it draws on consumer behavior, where consumers have sort of a bounded rationality. They can relate that metric more easily to their own circumstance. How much am I paying on my bill every month? How much could I offset?

I also want to say here, though, that if we've done everything up to this point, if we have a well-defined model, if we have all the macro factors, if we're estimating the economics well, there's many other types of models, decision adoption models that we could insert here.

So, I know that generalized Bass models are an interesting model that you can insert here. Discrete choice I think is also another interesting method that one could use, where you can measure both the utility of economic drivers, but also noneconomic drivers.

And then I think another growing area here is machine learning. Machine learning basically takes the theory out of it and says can we uncover the principles of adoption without, you know, defining how that should work theoretically.

Okay, so where do we go from here? This is sort of my prognosis on the issues that I think will be growing more important over the next decade.

So, as Melanie mentioned, spatial forecasting to understand distribution resource planning issues is going to become more important. As we have noted a couple times earlier, historic PV adoption is clustered spatially. Rich neighborhoods tend to adopt more than poorer neighborhoods. And, when my neighbor adopts, I'm more likely to consider adopting as well.

So, we really have to understand not only how much there's going to be, but where it will be adopted as well.

We also have to understand the interactions, especially in load shifting for other complementary technologies, like electric vehicles, home energy management systems, distributed storage and so on. And so I think that these are just going to complicate the picture even more because they just complicate what the economics look like and how the post consumption load patterns look.

Also, you know, at least in California the market has been very successful. We've reached a certain critical penetration level where most of the early adopters have already adopted. And so now, we're starting to see what does the full market look like.

What does the mass market look like? And I think that the drivers for adoption for that mass market are going to be very different than those from earlier adopters. So, that's something that might throw a curve ball.

Okay, so in conclusion, I think that forecasting DG adoption is quite hard, but the literature is growing quickly. There are a growing set of models, algorithms, data available to us. Researchers, both academic and in the national labs, are actively researching this.

In my experience, the most successful methods tend to use available data, historic data to calibrate models, but also use scenario analysis to understand the key tipping points of a system.

The next generation of forecasting is going to need to include spatial components to it, especially for distribution resource planning.

And then, as I just said, complementary technologies, such as energy storage, electric vehicles, et cetera, are going to grow in relevance, and particularly as consumers start to switch to time-of-use rates.

So, thank you for your time and I'll take any questions in the available time.

CHAIR WEISENMILLER: Yeah, the first one is just I think this is a general request of anyone doing a presentation and they have a model. It would be useful to have your -- you know, your R squared submitted in the record. Obviously, I winced when you said .5 R squared and it was like, oh, my God, I'm not sure I'd buy coffee with .5 R squares. But, you know, we need to get some way of cross comparing the different models.

MR. SIGRIN: True.

CHAIR WEISENMILLER: You know, and also to the extent there's a clear description of what the key variables are since, again, it seemed like some of the variables, you could look at the size of your house or you could look at income, you know, and they're correlated. So, the question is what are you really doing the regression against.

So, that just generally, I think we need to get a sense of how good all the fits that people are looking at.

I think the other thing is on the spatial side, along with the sort of sunlight, one of things we need to take into account is cloud cover. You know, at least in California, if you're looking at doing the LIDAR stuff, San Francisco's going to have a much different story than Sacramento, just looking at coastal fog. So, it's important to really start looking at that type of stuff.

Also, just trying to understand how much -- again, this is great. But where NREL can really help us is looking across the states. You know, it's always -- you know, we think we know what's the most important things in California in terms of policies. But, certainly, if you could then help us cross-compare it to Hawaii, or New Jersey, or some of the other leading adaptors and say, okay, what is really going on, that would help a lot.

MR. SIGRIN: Sure, sure. Thank you.

CHAIR WEISENMILLER: Andrew?

COMMISSIONER MC ALLISTER: You know, I'm not going to add on. I agree with those questions. I guess, a lot of great stuff and really glad you're doing that. And you're very familiar with Marin's work, and Melody's doing a lot of good stuff, as well. So, I mean, Texas and -- UT and some universities in California, and a couple of other places really is where a lot of where this work is going on. So, thanks for that.

I think I'll let the proceedings continue. I see Heather over there, looking a little bit nervous about our time. So, but look forward to your contributions to all this. This is a really good discussion.

MR. SIGRIN: Thank you.

MR. GARCIA: All right, thank you, Ben.

So, now we have Erin Boedecker joining us via WebEx, with EIA's perspective.

MS. BOEDECKER: Hello. This is Erin, the bodiless voice on the phone. Thank you all for allowing me to participate and asking me to explain a little bit about EIA's perspective on PV adoption.

I will be speaking from the end use distributed point of view. And let's go to the next slide and proceed from there.

So, just a little bit about what I'll talk about. First, I'll give you a look at our most recent projections, just to see what differences we've seen most recently in our outlook. And then, I'll talk about our current methodology a little bit. And as I talk about that, I'll talk about some of the issues that have been touched upon and some of the ones we find when we're trying to represent the nation as a whole. And so, the second two bullets will kind of be intertwined.

And I'll finish up with some of our considerations and thoughts going forward from this point.

So, the next slide, please. So, our newly-released Annual Energy Outlook 2016 incorporates the extension in the Federal Tax Credit. And that, along with our decreasing PV costs, relative to earlier assumptions, has greatly increased our outlook for distributed PV.

I know some questions were asked earlier about the relative nature of residential versus commercial/industrial. In this case, by the time you get to 2040, we're looking about 26 gigawatts of commercial capacity and 62 or 63 gigawatts of residential capacity. And you need to consider that nationwide there are a lot more households and roof area from households than there are commercial buildings.

We look at it from the perspective of commercial buildings as far as actual installed capacity. So far, the commercial sector has adopted any of the industrial installations and going forward we do have a size range that we're looking at. Our industrial sector model does not currently include any solar projections.

So, the next slide, please. Our current methodology -- I think I'd like to back up just a little from this. It does say that residential and commercial projections are developed at the census division level. I also want to point out that our end use models are annual models. So, what we send over to the power sector as generation or what we subtract from our demand for electricity to go over for electricity demand that needs to be met by the grid is an annual value, rather than we don't incorporate seasonality in our end use models.

Our only way to address that, at the current time, is we ask the power sector to send us end use level prices.

So, for PV we're looking at a cooling price, rather than an average price for electricity. So, we at least get some measure of the difference in price that would be more related to when PV would be generating.

Our parameters are a lot like Ben just mentioned on the Solar DS model. We use a 30-year discounted cash flow in both the residential and commercial sector. We look at technology costs and also performance. We include federal subsidies and financing parameters, both loan rates on the residential side, and we use the mortgage rate, and on the commercial side we look at the general loan rates for the commercial sector.

We also include any favorable depreciation methods in there. So, we're trying to get a picture of the actual outlay that businesses and homeowners will go -- will see.

We, of course, look at solar installation, the solar resource. And we do look at the electricity load.

And it says “average” here, but again we’re looking at the census division level. And so, on the residential side we’re looking at years to positive cash flow. The commercial sector uses an internal rate of return to determine how attractive the purchase is.

The next slide, please. Just to take a little look at what we are assuming for our cost declines over time, they have shifted a bit from last year’s annual energy outlook. And by the end of the projection period, residential installed costs are about $2,170 per kilowatt DC and commercial costs are more in the range of $1,700 per kilowatt.

The next slide, please. So, I mentioned that we project -- develop projections at the census division level. But in order to get at the heterogeneity that was mentioned in some of the earlier presentations, we’ve incorporated niches within the census division by overlaying maps of solar installation with electricity rates, to come up with areas within census divisions where you have more favorable, more attractive areas to adopt PV.

On the residential side, just recently we’ve taken a marginal price approach and we were able to use zip code data from the RECS, the Residential Energy Consumption Survey, that EIA conducts every four or five years. And we were able to use unpublished zip code level data to map with solar installation data at the zip code level to get a more accurate representation of the solar resource.

In addition, we were able to use monthly billing data to develop more of a marginal price, rather than an average price. And so, we're looking at these niches as far as marginal price estimates, which I think will help get us closer to looking at a rate structure than just an average price overall. It also includes a measure of the average roof area available to get to that technical potential.

On the commercial side, we haven't had the benefit of recent survey data. Just recently, in 2012, Commercial Buildings Energy Consumption Survey data has been published. And so, we're hoping to, as soon as we have time, do a similar marginal price approach for the commercial sector.

So, I won't go through all the sub-bullets. Please go to the next slide. We do incorporate some measure of the technical potential. In addition to just looking at the average roof area per household, we're looking at how much roof area is suitable for PV installations. And these are our current assumptions.

We're looking forward to devouring NREL's recent study to see if we can get a better, more accurate depiction of our technical potential.

I guess I want to also point out that as our assumed conformance improves in the projections, we also recognize that that will increase the technical potential because you can set more capacity in a smaller area.

The next slide, please. So, those are measures we’ve taken to try to incorporate more fully real world aspects. But we don’t fully capture some of the details. And this slide points out some of those. We can’t really represent tiered rates. We don’t have specific net metering terms and conditions represented. Although, we do have some consideration of variations in policy across the country.

We use something we call interconnection limitations, that are developed from the desires, state level regulations and policies. We turn those into factors that we aggregate up to the census division level that gives a census division propensity to adopt based on how easy it is to connect to the grid. And we assume that those limitations will decrease over time in our projections.

You can see for yourself some of the other things that we can’t -- we don’t represent in our aggregate model. And currently, macroeconomic and social factors are not explicitly included in our purchase decisions. We are looking at just years to positive cash flow or how economically attractive it is.

For near term and actual installed installations, we get around that somewhat by we calibrate to whatever the most recent historical data we have. And EIA's surveys haven't, in the past, captured distributed PV to the extent that we have a full picture. So, we've been using the State Renewable Energy Council Reports that have come out, annually, and aggregated up from their state level totals. And currently, we're using GTM, the Green Tech Market reports that they provide to CEA, as our basis for installed capacity.

And then, we take into consideration the states that have rebate programs that are substantial and try to do additional near term adoption that's in addition to whatever the model economically adopts.

The next slide, please. Policy-wise, we do incorporate federal policies, tax credits. We are technology specific, and so it's fairly easy for us to incorporate specific tax credits for a technology. And we do incorporate depreciation strategies.

On the power sector side, for utility-scale PV, we incorporate renewable portfolio standards. We haven't had the luxury of being able to incorporate those at the end use level.

We don't incorporate state or municipal tax credits explicitly. But as I mentioned, we try to capture near-term adoption for states that do have rebates, or also states with solar-specific targets near term.

We don't explicitly incorporate net metering. We actually assume global net metering in the sense that we assume that the customer will recoup the retail rate on whatever self-generation they have. So, our interconnection limitations that I described get at different policies in that regard.

And also, we don't explicitly include third-party ownership. But the fact that we incorporate a mortgage rate, we assume that for new construction homeowners will incorporate the cost of the PV system in with their mortgage. It's more favorable than assuming that they pay the entire cost up front.

And I realize that I didn't actually put in a slide that shows our penetration function. It is similar to the Bass model that has been already shown on the screen. We have an S curve for early adopters. And we do have a maximum penetration rate of 75 percent of new construction, even if you have payback of less than a year. And that's to put in some limits that incorporate that not every household or building will adopt solar, even if it's of immediate benefit to them.

The next slide, please. I just explained how we currently project PV adoption. We do have an alternative method that's currently being considered. It's more along the line of the agent models that Ben just talked about. It uses statistical models with zip code level data from states to estimate the effects that macroeconomic and microeconomic variables make on household decisions to adopt solar PV.

Some of the variables that are considered are income, median income at the zip code level. And I think that also would get closer to considering rates, rather than just an average price.

Of course, the solar resource at the zip code level. The retail rate, the number of households, also households that have already adopted solar, to get at the propensity to adopt, if your neighbors have already.

It does incorporate the installed price per watt, for PV. And also, population density. It gets at rural versus urban to some extent.

There is no explicit account for roof area, which rules out a distinct technical potential. But the population density is used as a proxy in this regard, too. And it is calibrated to historical estimates to adjust for policy differences.

So, if you go to the next slide, that's all I have. I looked at the time and thought that this would be about what I could fit in. As I said, I incorporated some of the issues as I was talking about the methods. But I'm open to questions.

So, thank you, again, for inviting me to participate and I'll be happy to answer any questions you've got. Thank you.

CHAIR WEISENMILLER: Great, thanks. I've got a couple and these are probably framed in a way which you can respond. Certainly, other folks can, in writing, later do so. And these fit on both the plus and minus side of the ledger.

So, what I'll characterize as the minus side of the ledger, one of the things which we're struggling with, particularly in the context of SB 350, which is requiring us to do work on EJ issues, is that, obviously, it's not -- everyone doesn't own their own house. So, if you look at just the physical count of houses, you know, and say let's diffuse out from there, somehow if you're -- if you rent space, it's unclear how we affect that market.

Or, similarly, you know, I've worked a lot on the commercial sector. If the triple net leases, again, you can go in and talk to them, it's just not going to happen because of that separation of cost and benefits.

MS. BOEDECKER: Right.

CHAIR WEISENMILLER: Or, similarly, if you've got a lease program, and all lease programs have a FICO cutoff and it's getting lower and lower. But at some point, if your FICO is below that bank cutoff, it's just not going to happen. And so, we need to incorporate those things.

And at the same time, in terms of policy actions, when you talk about new construction, we're actually looking forward to doing zero net energy building standards in 2019-2020. Looking at Commissioner McAllister who's, you know, on the other dais is more in charge of that.

So, because we assume that even if it's incredibly cost effective to do it when you're building the house, that builders aren't going to -- you know, again, there's the builder cost, there's the homeowner savings. And so, we need to be figuring out in our forecast what happens when we go ZNE.

And the other part I'm sure people are going to ask us is that a number of major California commercial/industrial customers are making big commitments here. You know, Apple, Google, Kaiser, you k now, bit numbers of megawatts are coming in that, or even the Department of Defense. You know, Secretary Mabus is hitting or exceeding his goal of a gigawatt.

MS. BOEDECKER: Right.

CHAIR WEISENMILLER: So, you know, again, we've got to somehow, in the residential/commercial space, take into account some of these institutional things because, ultimately, we have to come up with policies this year on how do we overcome some of those institutional things. But also, we can't miss the commitments coming out from large users, the military, and the impacts of our ZNE standards.

So, do you have suggestions, either right now or in writing, on how we can address these three issues. And certainly, again, encourage all of the other speakers to help us think through some of those.

MS. BOEDECKER: Okay, so --

COMMISSIONER MC ALLISTER: You know, I'd just add to -- oh, go ahead.

MS. BOEDECKER: Okay. Okay, so I guess I don't have any ready answer as far as addressing institutional adopters or actor agents, other than I think a lot of places where this occurs are places where there are RPSs in place so they get credit. There's some other incentives for them. And, yes, they're corporate wide, but a lot of the places that it's going in are places where those incentives are in place, in one way or another, whether it's tax credits, or whether it's renewable energy credits, or whatever.

So, I do believe that to the extent that you're already incorporating some of those policies or credits that you'll pick up some of the larger adopters that are out there.

But as far as explicitly taking that on, incorporating I guess income levels for residential might somewhat get at the renter issue where if they're not -- if they're not owning the home, then they're not likely to be -- less likely to be in the higher income category and less likely to adopt.

COMMISSIONER MC ALLISTER: Yeah, thanks. I guess I just want to put a finer point on what the Chair said. I mean, I think part of the complication here is that this is still a policy-driven arena to a great extent. Maybe not what it was a few years ago but, still, there's a new law, AB 693 I think it is, that's going to fund 100 million times 10, over the next ten years, 100 million a year for low-income, multi-family housing, for example, so that's going to have some impact. I think it’s 300 megawatts or so.

And, you know, as the Chair mentioned, the residential side ZNE by 2020 and commercial we’re headed to 2030. The outlines of those, you know, those don’t exist, yet. The outlines are still TBD, but we know we’re heading in that direction. So, how do we kind of quantify that?

And I guess it leads to a bigger question, and maybe it’s mostly for Ben, but to the extent that forecasting is about understanding uncertainty and that this and the other wedges, you know, that sort of get layered onto the demand forecast, in this arena how do you quantify uncertainty? You know, and sort of say, well, here’s our best guess. Here’s the curve, but the bounds are this big or this big. And how does that sort of propagate?

And maybe that, then, is a follow-on question for staff about how that gets propagated into the forecast, itself?

But you can triangulate with a bunch of models, but at the end of the day you kind of end up with uncertainty and there are ways to quantify that. And I guess I’m wondering how much you guys have thought about that?

MS. BOEDECKER: So, I guess I’ll answer first, since no one else has just jumped in.

COMMISSIONER MC ALLISTER: No, Ben was grabbing his mic, but go ahead.

MS. BOEDECKER: All right. I think our answers would be similar. So, our first approach at addressing uncertainty in our forecast or projections is to run alternative scenarios, just as Ben was talking about earlier in his talk.

The new projections that I put up first are for the reference case because that's out already. But in another week or so we'll have all of our alternative cases for the Annual Energy Outlook out. And included in there is an extended policies case which extends tax credits, at the federal level, at their current percentage.

And it also extends the Clean Power Plan so that there will be more stringent goals to meet there, as well. And I think all of that feeds into providing that range.

We have other cases that look at it from different aspects. And also, we hope to do more analysis, separate from our annual projections, that will look at more scenarios for PV, in particular.

COMMISSIONER MC ALLISTER: Great, thanks.

CHAIR WEISENMILLER: No, that's great. And I was just going to say, certainly encourage you to the extent you're thinking of research or surveys in this area, to the extent we can coordinate on the surveys or research that would be great.

MR. SIGRIN: Yeah, thanks. I think it's a great question. You know, ultimately, I guess what you're asking is can we determine a prior distribution of the uncertainty factor. And some of then we can, some of them we can't.

I think one of the more trackable ones would be technology costs. So, one of the things we do at NREL is compile census forecasts of technology costs reduction over time. From there you could estimate, you know, the quantiles of uncertainty.

There's other ones you don't have any prior knowledge. Rate restructuring, for example, is something that there's just not enough empirical basis to do so.

So, I would agree with Erin, most of the way that we incorporate that -- unless we can have some prior distribution, we generally run it through scenario analysis. And mostly to understand what are the key factors that could have, like I said earlier, a tipping point in the system that would -- you know, not differences of 1 to 5 percent differences, of 50 to whatever percent. Thank you.

COMMISSIONER MC ALLISTER: Oh, go ahead, Asish.

MR. GAUTAM: Yeah, so regarding uncertainty in our own demand forecast, we have three different scenarios for the economic and demographic drivers. And on the DG side that does impact our floor space estimate for the commercial side, and population per household and usage on the residential side. We've mainly been focused on the handling of uncertainty on economic and demographic scenarios.

But in the 2015 IEPR we also addressed uncertainty in PV technology. We had some scenarios from the PUC's (indiscernible) study. And then we also looked at some differences in the NEMs, how NEM may evolve over time. So, in the load demand forecast we assumed that retail credits will continue, there will be no other charges. And then, in the high-demand case we imposed demand charges and fixed export rate for the excess production.

These scenarios are kind of the only way we have, the ability kind of puts some downs in a lot of these things that are very uncertain. So, it's very challenging.

COMMISSIONER MC ALLISTER: Yeah, yeah. So, but in the forecast context I guess, if I'm understanding, what you’re basically saying is that sort of you pick the scenarios that feed into the high, low mid cases --

MR. GAUTAM: Yeah, yeah.

COMMISSIONER MC ALLISTER: -- and sort of that’s how the variability is represented. Sort of not air bars around each scenario.

MR. GAUTAM: That’s right.

COMMISSIONER MC ALLISTER: Yeah, okay, that makes sense.

CHAIR WEISENMILLER: Yeah, I would just note that old classic financing energy efficiency, you know, one of the books I edited, there was a paper by, I’m trying to remember whether it was George Schaefer or Derek Hansen.

Yeah. And basically, what we looked at on uncertainty is -- the conclusion was macro things had a bigger effect on projects than micro things. And so, you know, you’d screw around a lot on cost of, say, technology. And then there would be an oil price shock, or an overall tax change, or restructuring would occur. And, you know, then your investment either looked incredibly stupid or incredibly smart, regardless of everything else you had optimized on the micro level.

COMMISSIONER MC ALLISTER: A lot of this, to me, seems like it really depends on if the overall rate environment kind of supports, you know, allows enough of a margin to be spread across from consumer to supply, to service provider, to enable that package to be really marketed en masse and get scale. You know, and I think there's quite a bit of uncertainty but I think, you know, not as much as maybe a lot of people think.

Anyway, that's my two cents. This is a great panel, yeah. Great, thanks a lot.

MS. RAITT: So, we can move on to Chris Kavalec next, or if you wanted to open it up to the stakeholder response and comments.

So, next on the agenda was opening it up to stakeholder response and comments. So, I don't know if there's folks in the room who have any comments, or questions for our speakers on that panel?

Otherwise, we'll just move on to Chris Kavalec. Chris, great.

MR. KAVALEC: I am Chris Kavalec, with the Energy Commission Staff. I apologize for cutting into the lunch hour, but this should be relatively quick.

I have the distinct privilege of talking about everybody's favorite topic, weather normalization. And I'll start with a brief review of what weather normalization is and why it's important.

When we do a forecast, a peak forecast for a given planning area, what we have to do is weather normalize peak demand to the last historical or base year. In other words, estimate what peak would have been in the base year had there been “historically average weather”.

The reason we have to do this is because our forecast, itself, assumes average weather, except for an adjustment that we make for climate change.

So, this weather-normalized peak serves as the starting point for the peak forecast and, therefore, is a very important consideration. The higher or lower as your weather-normalized peak to begin with, the higher or lower all else equal is going to be your peak forecast. So, this generates a lot of discussion, always.

The method that we currently use, we use a regression analysis using the last three years’ of hourly load data that we get from CAISO, to estimate the temperature response of load in a given TAC area, PG&E, Edison, or San Diego.

And then this temperature response is applied to historical temperatures going back 30 years, and that gives us the distribution of annual peaks. And the median of this distribution serves as what we call the one-in-two weather-normalized peak demand for the last historical year.

And other IOUs and CAISO have their own methods, which all have strengths and weaknesses. So, everybody comes up with a slightly different estimate or a significantly different estimate, sometimes, for a weather-normalized peak.

And a problem we've encountered in some of our recent forecasts is that the IOUs and the Energy Commission are not always able to agree on a weather-normalized peak in a timely manner. Meaning, we are sometimes still debating a weather-normalized peak right up until the point where we release our forecast, and people don't like that.

And this happens because, you know, the IOUs have their own schedules, other things they're concentrating on and we don't really have a coordinated process. It's been more informal up to this point.

So, the solution I'm proposing is a structured process for weather normalization analysis that includes us, the IOUs and CAISO, since CAISO is one of our main customers for our peak forecasts. And this process would have specified and agreed upon start and end dates, with an end date that would be -- that would leave us enough time, and the end date -- the process would end well before the forecast is released.

And this process would include a full discussion of our methods, as well as the other IOUs and CAISO, oral and written comments. There would be a couple of in-person meetings, a DAWG meeting or two to talk about this stuff and make presentations. And then, a reconciliation process.

So, the key steps look like this. We would have an in-person -- once we have some preliminary results for our weather-normalized peaks, we would have an in-person meeting, a DAWG meeting, and we would present our method and results to the IOUs and CAISO. And we would also provide documentation of our method and results.

And then, after this meeting, we would allow IOUs and CAISO roughly a week to comment and ask any further questions on how we came up with what we came up with. And at this point, we would then hold the IOUs and CAISO responsible for understanding our process, our methods and our results, so we can avoid last-minute questions on how did you get this number, that we've had in the past.

Once we get past this part, we would have a follow-up meeting, if necessary, if we find we have significant differences with the IOUs and CAISO. And we would begin sort of a reconciliation process and try to come to agreement.

And another week, if necessary, to back and forth, e-mails, phone calls to try to come to agreement. And hopefully, by this time, we will have reached that goal. But we are also leaving a couple days in the process for upper management to get involved, if we haven't gotten to any agreement by the end of this process.

So, the schedule looks like this. We would start in the middle of October. The reason we have to wait until then is that we don't get our September hourly loads from CAISO until the middle of October. And September, obviously, is part of the summer and a potential peak month.

Our preliminary estimates would be available at the beginning of November. Now, I should mention this is a specific schedule meant for the 2016 IEPR Forecast Update.

So, in the beginning of November we have our preliminary estimates of weather-normalized peaks for the IOU TAC areas. Also at the beginning of November we have our DAWG meeting and we go through, and fully explain our method and our results, and get feedback. And the next day, after that, we would provide full documentation of our results.

And then the following week, the IOUs would go back and evaluate our methods and numbers, and provide any questions and comments. And again, if we have -- we find significant differences, we have a follow-up in-person meeting. And leave a week after that for further discussion. And, hopefully, coming to agreement at some point.

And then a couple days, as I mentioned, left in case we are at an impasse with one or more IOUs and we need management to get involved, in an attempt to resolve the situation. Hopefully, that won't happen.

And so, by the middle of November we have -- we will, hopefully, have our final estimates of weather-normalized peaks. A month, at least roughly a month before we release and present our updated forecast for 2016.

And this is what will happen at the end of this.

(Laughter)

MR. KAVALEC: The Energy Commission staff will be -- are in the middle of this group hug because everyone's so happy with our process.

So, we've talked to the IOUs and CAISO, and they are on board and have committed to engaging in this process during this roughly one-month period. But they may have some comments of their own to make, after I turn to the Commissioners for any questions or comments.

CHAIR WEISENMILLER: Yeah, actually, as you know, this has sort of come up a couple of times at the very end of our process which always sort of exasperates some Commissioners, at least.

And so, when you talk about the issues, one of the questions I thought -- one of the problems was the choice of weather data. You know, my impression has always been we tend to use publicly-available weather stations, which tend to be the airports, or whatever. And some of the utilities have their own networks of weather stations. And, particularly, as we go to a more and more disaggregated forecast, obviously one of the things, particularly for peak load, what we'll have to worry about is disaggregated weather information.

And so, just how well are the weather stations correlated between what we use in our forecast and what the utilities use in their forecast?

MR. KAVALEC: The weather stations are different and they have different weightings, based on different types of analysis. And that is always a concern.

In this process, what I am planning -- what we are planning to do during this reconciliation process, if it's needed, is run our models with both our weather and the IOUs' weather and see how much difference there is, and take it from there.

I'm hoping that that's not going to be the major source. But if that is the major source, then we will have to go down a step and start talking about our weather stations and the weightings that we use.

CHAIR WEISENMILLER: Yeah, I would think, again, we're just trying to clear out the clutter at this stage. So, I would suggest, if we could get a filing in this docket, coming out of this case that just does the comparison of weather stations, and at least starts framing things. So again, if we get to the very end game this doesn't suddenly pop up again.

MR. KAVALEC: Okay.

COMMISSIONER MC ALLISTER: So, on a related kind of note, is there agreement on how to then look at how to take whatever data, if there's a consensus data or weather data each party's using, and agree on sort of the future -- the future proofing of that data and adjusting it for climate impacts, et cetera? I mean, are there various processes to do that or are you agreed on that procedure, or is part of the goal here to agree on that, itself?

MR. KAVALEC: No, this procedure is not to agree on a specific method. It's to try and reconcile differences in results. I mean, we don't -- you know, one path to take would be try and get everybody to use the exact same method. But that's not always good because, you know, different perspective, different ways of doing things give you different insights.

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: We don't want to make everything uniform.

COMMISSIONER MC ALLISTER: Yeah, okay. I mean, I guess I'm just wondering, you know, to the degree that climate impacts are something that should be talked about, you know, to tee it --

MR. KAVALEC: Yeah and so --

COMMISSIONER MC ALLISTER: You know, we talked about this in the last forecast, the IEPR, you know, using TMY data, or whatever, is inherently backward looking, so how do we adjust it for what's going to happen in the future, we think, right.

CHAIR WEISENMILLER: Yeah, a couple of forecasts ago one of the things we did was -- one question is, once you get weather data, how many years of that are you using.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: And we sort of shortened our period. Edison was using -- I think we may have been using 15 and they may have been using 30 or, you know, whatever the right numbers were. But anyway, with climate change, the notion was to go with the shorter period so that, you know, we were more reflecting current weather, and as opposed to weighting the longer term.

MR. KAVALEC: That's right.

CHAIR WEISENMILLER: Yeah. So, anyway, that's at least part of the mix. But I don't -- at this point I don't think, although again that may be something that's useful just to get down on paper so we -- that, you know, if there's any big differences on the time periods at this point, as much as potentially the weather data, or the weightings. You know, there's all kinds of magic that goes into the mix.

COMMISSIONER MC ALLISTER: Yeah, the last 15 years isn't necessarily the same as the next 15 years.

CHAIR WEISENMILLER: Yeah, right. But with that note, I guess, I don't know if we need to come up to the microphone, or in writing, or something. But I'm just trying to make sure that, indeed, affected utilities say, yes, we agree on this process. You know, this is where we are now, at least for the process you're laying out.

MR. KAVALEC: Yeah, so I'll ask the IOUs if they want to come up and make a comment or two.

CHAIR WEISENMILLER: In the speak now, or else we agree you bought in. Or, you can do written comments, obviously.

MS. SHEN: My name is Hongyan Shen. I'm from Southern California Edison. First, I'd like to thank Chris for, you know, coming up with this proposal on standardized weather-normalization analysis and build a structured way for all the stakeholders to work with CEC to, you know, reconcile any significant differences in weather-normalization analysis.

As we all understand, this is also an important part of the Commission's peak demand forecast. We really appreciate the opportunity that this new process will create for us. And, you know, we are looking at getting more understanding through this process, as in a way such that we can understand better what drives more significant impact to the weather-normalized analysis results. And, hopefully, bringing more refinement to both CEC and our own analysis in the future, that we could align our views more closely.

So, I think this is a great start. But at the same time, I think there's a lot more we need to gain understanding from both ends. I agree, you k now, the questions you raised are great questions in terms of whether weather station data drives more differences, or climate change, or other part of the -- you know, the other drivers may impact analysis results more. And that's, you know, hopefully the process will bring us more understanding in those areas that we would really build more consensus more easily in the future.

CHAIR WEISENMILLER: Well, I think the last -- I'm not -- two times ago, and perhaps the last time there was also a data issue. That, you know, obviously, Chris gets data from the ISO and under protective order.

You have data. One would like to believe the two match, and somehow they don't.

MS. SHEN: Yeah, that --

CHAIR WEISENMILLER: And so, one of the other things which I was sort of determined to do was to get the data to match this time. AT least any -- along with weather normalization, that basic data issue, quote/unquote, be resolved.

MS. SHEN: Yeah, we'd definitely like -- that's still on our wish list. But I'm very encouraged, Chris had come with the great idea of getting us to work closely with CAISO so that we can work out a realistic, applicable solution to obtain similar data that CCU ties, in a way that we can eliminate those drivers in terms of impacting all our results.

CHAIR WEISENMILLER: I've told Ron Nichols that. You know, this happened to me twice. So the third time, I'm just going to lock everyone, bring a sleeping bag, you're locked in a room and don't come out until you agree.

(Laughter)

CHAIR WEISENMILLER: So, you know, there's a process between now and the end of the year, work through the issues or at the end it's going to be that don't go home until. So, let's work it out now.

MS. SHEN: Yeah, like Chris painted out here, I hope we can hug each other earlier than later.

(Laughter)

CHAIR WEISENMILLER: Great, thank you.

MR. SCHIERMEYER: I'm Ken Schiermeyer from San Diego Gas & Electric, the Electric Forecasting Manager. And I'd like to thank Chris for suggesting this process. We're committed to it, to the end of the year to reach some sort of reconciliation.

You know, in looking at the schedule, I agree with Commissioner Weisenmiller that just the data, you know, making sure the data is one in the same is going to be, you know, the first priority. You know, in speaking to the weather data, we try to use publicly-available weather data. But sometimes it's missing so we have to fill in blanks.

So, in the past we've provided that to CEC and plan to continue to do that going forward.

The schedule, I'll say one thing, the schedule seems pretty fast. So, I would like to suggest, where possible, you know, say it's weather data, if we can do it beforehand. And when the schedule starts, we focus on the methodology, you know, where possible. I know the load data comes from CAISO and it's not available. But maybe, if it's partially available, maybe we can compare as we go along. And we'd be willing to do that.

CHAIR WEISENMILLER: That would be great. I mean, obviously, we have last year's data. We don't have this year's. But, yeah, the more we can debug the differences from last year then, presumably, that gives us a head start on this year.

MR. SCHIERMEYER: I agree.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: Yeah, if we can do some of these comparisons beforehand, such as weather, and the IOUs have time to do it, that would be great. Thanks.

MR. RAY: Good afternoon, everybody. My name is Sam Ray, from PG&E. I'm an Analyst in the Forecasting and Research Department. I'm admittedly new to this process, so my comments will be brief.

But I appreciate Chris's proposing this new schedule and I understand that it has been trying in the past. So, while I can't speak to the methodology issues at this point, I would echo the previous comments that getting this process started sooner than October, at least in identifying the correct data sources would be great.

And for us, at least, that October 14th, I think, date for comparing the weather-normalized peaks could be a little bit early, just in terms of gathering the recorded peaks during the summertime. So, I think it's a work in progress, but we're definitely supportive of making this a more formalized process. Thank you.

MR. EMMERT: Hi, I'm Bob Emmert with the California ISO. I'm Manager of Interconnection Resources and my team does the summer-ahead type forecast. And we've worked with Chris in the past. And we were able to work through the weather-normalization process in the past. But I really appreciate what Chris is doing here to make that more formal, and more of an iterative process to come to a solution that I think is going to work out much better for all of us.

And we'd be quite willing to work with everybody, related to the data issues, to make sure that we're all using consistent and understanding the datasets that we are using, and what they do represent. So, we appreciate this process and support it.

And I would agree, as well, that to get ahead of the curve and have some meetings ahead of time, prior to the schedule actually being officially kicking off, would really be helpful. Thank you.

CHAIR WEISENMILLER: Anyone else?

Yeah, Chris, this may be great DAWG workshop stuff between now and when Andrew and I have to dig into it again.

MR. KAVALEC: I'm sorry, the --

CHAIR WEISENMILLER: I said, some of the follow up might be great DAWG group meeting stuff before you come back to deal with Andrew and I.

MR. KAVALEC: Yes, definitely.

CHAIR WEISENMILLER: Yeah.

So, Heather, it looks like we are --

MS. RAITT: Ready for our lunch break.

CHAIR WEISENMILLER: Yeah, I think so.

MS. RAITT: And we were going to come back at 1:15, is that --

CHAIR WEISENMILLER: Yeah, let's do 1:15. Yeah, let's crunch along a little bit. Thanks.

MS. RAITT: So, we'll try to get back on schedule and we'll come back at 1:15. Thank you.

CHAIR WEISENMILLER: Great.

(Off the record at 12:25 p.m.)

(On the record at 1:21 p.m.)

MS. RAITT: Welcome back to the IEPR Workshop on Methodological Improvements to the Energy Demand Forecast for 2017 and beyond.

So, our panel this afternoon is on the Analysis of Potential Shifts in Peak Hour Caused by Demand Modifiers.

And our first speaker is Jeff Billinton, from the California Independent System Operator.

MR. BILLINTON: Good afternoon. As indicated, my name is Jeff Billinton, with the California ISO. I'm just going to give you a bit of an overview of the forecast and the peak shift impact, particularly as we've seen with the PV. And the impacts for the ISO, particularly from the transmission planning perspective as we're going forward.

And also, just to echo in terms of Chairman Weisenmiller's comments as to the need to make sure we're consistent, the work that we've done to ensure in terms of between the processes. Particularly, the inputs, the forecast inputs between the ISO's planning, the CPUC's long-term procurement. And that's a major focus as we look at these kind of components is ensure that we're also consistent as we look at these impacts.

Because as we look at it, this is directly out of our 2016-2017 transmission planning process, we utilize the CEC's forecast. We're using the mid-forecast. As well as we're using the AAEE as identified in the IEPR. We use the mid-AAEE for the system wide studies and also in our economic analysis. We use the low mid-AAEE in our local area studies. And like I say, it's consistent with the forecast.

And in this year's, in the 2015 IEPR, the identification of PV and the impacts was identified as a potential with the peak delay, or peak shift and the impacts of it. However, the base forecast has -- doesn't take into consideration the peak shift impact.

In the ISO's transmission planning process, we were utilizing the CEC's forecast as the base, as it is in the IEPR, as we're going forward. As with the NERC reliability standards that we follow, we also are doing some sensitivities. This is one of them as we look at outputs of generation or those components.

But the base that we're using is the CEC's adopted forecast going forward.

And so, as we look at the peak impact, this graph is directly out of the 2015 IEPR Forecast document. I took the PG&E -- there's three. There's one for PG&E, one for SC, and one for San Diego. And for illustrative purposes, the line represents at the time of peak, with the PV profile. What is the PV output at that time of peak? And that's what's then used in our studies as we look at the PV output at the time of peak.

What we notice, as we're working with the PV, and if you take the PG&E, the load doesn't drop off significantly as the hours go out, but the PV drops down significantly. And so, if you're looking at in terms of PG&E's forecast or area, the forecast peak was at 5:00 p.m. If we look in terms of and shift it to 7:00 p.m., the PV is down to a small percentage. And these are per-unit of the peak load and the PV profile. But the load, itself, is still at a fairly high level with the PV is down at a reduced level.

And this, the next graph that we've looked at it is this is taking the data from the CEC forecast, and what the peak forecast would be. The blue line would be the gross load, which is also of importance to us as we're doing the transmission planning. The green line then takes into account -- or, actually, the bottom red line then is based upon the profile from the previous slide that I'd shown.

And the magnitude of distributed generation that is assumed in the IEPR forecast, for the PG&E area, that then leads to the green line, which is then the net load forecast on the PG&E TAC area.

And as you see, in terms of during the peak time, it starts to -- basically, the peak from the gross is decreased based upon the output of the PV. That is being identified at that time as kind of the output.

But as we look in terms of to where the actual peak is, the peak is actually at 7:00 and at a higher level. In the case of this, it's about a 2,000 megawatt difference on the PG&E area. And these are just -- this is in terms of just looking with the data that was in the forecast, it has an impact.

And as I say, this has a similar impact but is varying based upon whether it be SC or San Diego's area, because the peaks are slightly different. Peaks start at about 4:00 and shift anywhere from 5:00 to 6:00 in the SC and San Diego areas. But the principle is the same.

And so as we're looking at these, from the ISO's transmission planning perspective, we need to make sure that we're planning based upon the system peak. The NERC Reliability Standards, one of the conditions for the planning assessment is that it's studied under peak conditions. And with the peak shift in impact, just in terms of the question of the base forecast not taking the shift in, is not the peak that actually will potentially occur as we're looking forward. And so, that's one of the ones we've done it as a sensitivity. But it's in the base, as we're going forward, needs to be what is considered.

And as we'll hear, in terms of there are different methodologies to be able to look at how do we go forward with developing or determining this, is there other impacts other than the PV, as well, be it the AAEE, or the electric vehicles that have an impact on the peak as well.

But that's -- from the planning perspective, the peak is a critical component for what we need to make sure we have that reflected as we're looking at what are the needs of the transmission system.

The other, the impact of having the reduced, as we look at it right now is it understates the need in the future. Or, as we look at it in terms of existing approved projects, the need for them, but with the uncertainty of the load forecast or the load being actually higher than the base that we have. Having to try to manage the issues of that uncertainty that this creates.

And I will indicate, in terms of as we're looking at some of the areas, and some of the areas that have already some significant penetration levels of distributed PV in those areas, we are actually experiencing the peak shift in existing, like in 2016 time frame. The Fresno area is an example that we're actually seeing that the peak is actually shifting to the 7:00 time period today, based upon having distributed generation in those profiles, having the impact on the peak during the daytime period already.

So, that's, just to give in terms of context, in terms of from our need, the peak, and what we see or saw in terms of working with Chris. We've been working with Chris with regards to this, in discussions, and we would move forward. But that's the issues that we see right now so --

CHAIR WEISENMILLER: Thanks. Obviously, we're all interested in getting the right forecast. And at the same time, certainly, one is we're looking for people's data. You know, I know the ISO is sort of on one side of the meter. But, basically, if there's any ways you can help us really dig into the data questions, you k now, what's really going on?

And I know the ISO's done some work trying to figure out, as you look at the duck chart, which I'd have to say is related to the PG&E igloo chart was another way of getting at the same question, is you've been trying to deal with what's behind the meter that you can measure.

So, as staff tries to look at interconnection data, what data, if any, does the ISO have on what's going on behind the meter? I assume nothing, but checking.

MR. BILLINTON: Yeah, I'd have to check with Bob, but I don't believe we actually, really have much that would be behind the data -- or, behind the meter that we could use. We're really looking at it from the system data perspective on the transmission system.

But you're right, that data has a significant impact on how to take that into consideration for those impacts.

CHAIR WEISENMILLER: Yeah. Well, certainly, anything you have that might be useful, we'd appreciate it.

MR. BILLINGTON: Okay. Yeah, appreciate that.

CHAIR WEISENMILLER: Great. Andrew?

COMMISSIONER MC ALLISTER: I guess on the -- you could talk about just the level of geography or level of granularity, I guess, of the analysis that the ISO's typically doing? I mean, you sort of highlighted one service territory, but I bet you can drill down to load pockets or whatever other units of analysis that you think are important. And where is that now and where is it going?

MR. BILLINGTON: With regard to the forecast, itself, it’s at a fairly high granular level of the utility’s service territory area and how far it goes down in the -- in the CEC forecast, itself.

And then to develop, in terms of our transmission planning models, we work with the utilities, themselves, who do the allocation to the Bus, taking the CEC forecast as the starting. And in the case of the PV, so as we look at it, trying to model the gross load that’s there. And then the PV at the identified at-peak level is what’s in the -- we study in the cases.

So, the utilities aggregate or disaggregate that to the Bus levels for us, based upon their distribution information, and as we go forward.

In this year’s transmission planning cycle, this is the first one that we’re -- in the increase of the penetration of distributed generation that is included into the forecast, we’re modeling the gross load plus the PV into our base models. Which is important -- less important from a study State type model, because the net is probably adequate.

But as we get into dynamic impacts, the gross load and what generation is responding to that is critical for us. So, we use a lot of input from each of the utilities as to the disaggregation of that. And also, they're using, from their DRPs, and the information they have of where is the projected growth in the PV, in the development of the models.

COMMISSIONER MC ALLISTER: Yeah, okay. So, basically, at the Bus level is where you're --

MR. BILLINGTON: Yeah, that's what we need to be able to model so that it gets the transmission flows.

COMMISSIONER MC ALLISTER: I mean, are you noticing that there are -- I mean, depending on penetration at a given locale, you're noticing that that impacts the ramp. And that's sort of what you can see looks different depending on how you analyze what you can't see behind the meter?

MR. BILLINGTON: Yeah, well, that's one of the challenges of the behind-the-meter is without having visibility the forecast of it is difficult. Especially, you're meaning in terms of the operating time frame, as well, right now. And yeah, so if it's not there, it's an uncertainty, kind of in the operating in that realm.

COMMISSIONER MC ALLISTER: Okay, thanks.

CHAIR WEISENMILLER: And I guess actually the one thing we should make sure going forward, as to the extent you've got the DER pilot now, at this stage, and going forward as that plays out more and more, again, we need a way to figure out how to get data from that. But, presumably, modifying those subpoenas.

MR. BILLINTON: Agreed.

CHAIR WEISENMILLER: So, thanks.

MR. BILLINTON: Yeah.

MS. RAITT: Thank you. Next is Cary Garcia from the Energy Commission.

MR. GARCIA: All right. So, this is our Demand Analysis Office Preliminary Analysis of Peak Shift. I think I'm going to basically review a lot of what Jeff just said, with a little more detail into how we try to approach it, in this simplified example that we have so far.

As you can see, later on we're going to talk about long-term hourly load forecasting, so a lot of this analysis is going to kind of go into that at a later term, and especially in more detail at the hourly basis.

I'll explain a little bit more, but this is kind like a snapshot view that we've drawn out. So, it's a little limited at this point.

So, just some quick background. The way our forecast works, we have our sector models and that kind of gets input into our HELM model, our hourly load model, and then we get our peak shapes or our peak value for the forecast.

Unfortunately, this -- the underlying assumption here is that that peak shape kind of stays the same out into the future. So we know, now, that's not a good assumption to have going out into a 10-year forecast, especially.

So, there's plenty of load modifiers out there, in addition to PV, that we need to incorporate in order to have this peak shift effect, not only the hour, but the magnitude incorporated into the forecast into the future.

And so here, I mean, some of the consequences. ISO just came up and explained, you know, our forecast gets put into all these other analysis. And so, if you have this bias as far as the peak shift goes, that's just going to carry over into everything else and then we end up with trouble later on. So, that's something we need to address and something we don't want to happen.

And as I said, behind-the-meter PV is one of the biggest issues, but we also have electric vehicle profiles that we need to take into account in the future. Additionally, energy storage, time of use pricing, which will be happening, and our hourly AAEE impacts.

Currently, as far as electric vehicle profiles, we do have a contract with Idaho National Lab and they're working on getting us those profiles, so we'll be able to incorporate that into this analysis pretty soon.

So, just some information on the data and the approach that we took. So, our load data is coming from the 2015 ISO EMS data. We've generated hourly AAEE savings that we've used in other analysis. And then we took the profile that we've used for our forecast for EVs, and then added that into some of the graphs that I'm about to show. So, that EV forecast is basically translated into hourly impacts for us, on like a typical summer day. So, it's an average type of, I guess, metric.

And then our PV data, as Asish mentioned, comes from the CPUCs NEM interconnection data. So, we have that current through 2015.

So, once again, we have the hourly EMS data and we have the estimated PV production that Asish was able to put together for me. We combined that to recreate the consumption of each day of 2015. We scaled that consumption value, based on our forecast, out to 2026. And then, we re-estimated meter load by subtracting PV and the AAEE impacts from the adopted forecast.

And so, in this case what I'm showing or what I'll be showing is just some snapshots of what some of these days look like. So, basically, to observe whether or not this peak shift is happening and then what the magnitude of that could possibly be.

So, just some simple review of the findings. So, in this simplified projection we do find that included these effects does have shifts pretty soon. Here I say 2017, but you can kind of see it now. And as Jeff said, he's seeing it now, too, especially in those local areas.

And then, so the results here, we definitely get a better idea of the timing and magnitude. But as I said, this is definitely a simplified way to look at it, as a snapshot, and it will have to integrated into this hourly forecast in the future.

And lastly, we've kind of focused on like the peak situation, but there is some interesting -- just some interesting shapes to kind of look at when you look at off-peak, and some weather phenomenon that kind of come into play.

So, here's one way to look at it, pretty simply. So, I don't have 2015 on here, but if you look at the 2017 values for these three days in September, that I've simply scaled out to 2020 -- well, let me step back a second. So, you have to remember the 2015 weather in here just kind of gets carried over forward. So, all the consumption shapes and all the associated, like economic effects that could be in there are just carried over, it was just extrapolated out a little further. So, you have to reference it as everything being in 2015 time. Although, the growth has been applied to it.

And so we start, generally, so September 8th we start hour 17. And then, by 2020, we see the shift one hour going out, and that continues out to 2026.

In the case of September 9th, we see a much bigger shift. But what we're seeing here, though, is actually there's some -- there's the shape of the consumption has been dragged out a little longer. And I believe it's due to the temperature effects that are happening here. So, that's something we need to take a look at and how to -- it would be useful to be able to pull temperature out of there and kind of see what this looks like, and then kind of add it back in and play around with this a little bit.

Just to kind of start off with like a baseline, a normal year would be useful for this.

And then, similarly, with September 10th we see this hour 17, and as soon as 2020 rolls over, we see the shift go over and that carries forward.

I think from some analysis you wouldn't see a shift continuing forward, right, you'd kind of get to a certain point, this late evening time, when everybody's home, and it would kind of stop from there. So, hopefully, we don't have any weird consumption hours in the future and we have to do another set of shifting. But I don't think that will be the case, at least in the near term.

So, here's a little graphical representation of what's going on. As you can see, real quickly in that September 9th term, you can see that load kind of carrying out. But this, now, as the load starts growing that the PV production starts growing, you see this belly start to form and that load shoots up to that hour of 20 time frame there.

And this is another representation of specifically that September 9th, but grown out to 2026. So, right at the top there we have our consumption shape. And Jeff had a similar graph earlier. We subtract out that PV that's happening and you end up with this little green line. So, it's about 4,000 megawatts of PV. Subtract out the AAEE and that leaves you with this meter load, where our estimated meter load was. And that's kind of showing you what the effect is here.

But if you look at that green line further, you'll see that the PV production basically drops off. And this 1,400 megawatts of EV here is -- I should have made a correction here, but that's not actually happening at that peak time, which was about hour 16, I believe. That would be happening at hour 20. So, that's just adding to this shift that's going to occur in the future.

And this is just a breakout for the individual TAC areas. So, in this example here, for this particular day we saw a peak shift of just an hour. But you can see the little breakouts of the differences in hours. The energy efficiency impacts are still kind of carrying over so that's adding to this effect, too. But then you can see the PV production drop significantly. And then you have a little bit of EV loading coming on, too, at the end of the day.

The same thing with Edison. A slightly different shape, but same idea here. You see this little peak shift that occurs. You can look at the differences between the PV production has dropped significantly, again. A little bit more EV production, but the AAEE is still relatively the same.

A little different with San Diego's case. I believe, as I mentioned earlier, this is a weather phenomenon that I think is occurring here. The temperatures were pretty extreme and stay -- I think this is like 99, 100 degrees, around that, so it's pretty hot for San Diego's weather. But the same story.

In this case, though, PV production is gone completely, but you have a fair amount of EV charging. And AAEE has dropped a little bit, but still pretty high.

And so, observing shoulder months, you kind of see a little different story. You see a little belly start to form with the PV production and a little bit of variability in the production of PV.

So, one thing that I found, just in this particular set of dates here, is a significant belly forming when you start growing this out and the ramp that would have to occur to kind of come back up to that peak. So, about 3,000 megawatts between those four or five hours.

And if you look at September 2nd, when I sum it up to the ISO, it's a little difficult to see. But if I were to show you San Diego here, you would see a lot of up and down variation that's happening on that date and it's obviously going to be cloud cover that's coming into play. So, that's just another thing we need to be taking into account in this work house. You know, does that variability need to be included and how much of it.

So, just some conclusions real quickly. And this is basically steps forward that we need to incorporate into this. One of the issues is the EV profile that we currently use is definitely very generic. Having these more accurate profiles from real data in the next -- I think we're going to use 2013-2014 data and try to extrapolate this out a little bit to kind of get an idea of what those real profiles are. Because they're definitely not the same for across the State. I'm sure there's going to be differences and patterns are going to form when we have a better idea of how these operate.

Additionally, storage profiles will be very useful in this because we -- I think we -- it's not very clear exactly how storage is going to work. We have our -- I mean, we have a general idea on what's going to happen based on how, you know, you want to buy cheap and sell high, right. So, we kind of know what's going to go on there. But having some real data on that would be very useful for this analysis.

And lastly, time of use would be very important to incorporate here. But the same thing, I think -- I guess time of use, if the prices are a little low during that belly time, you kind of know what the effects are. But it would be really useful to spend the time to study that and see how that's going to be different across the different planning areas.

And then, lastly, the weather variations for these hourly forecasts that Chris will have will present next -- you know, do we need to normalize this based on history. And then, we kind of talked about this with weather normalization, I guess. If we're going to start normalizing the weather, that component, then our PV production for this analysis needs to be also, possibly, normalized. But at the same time still include variation for cloud cover and other phenomena that can affect this.

One issue that we've discussed before is, actually, during peak time if the temperatures do get hot enough, you will see a little dip in your production from PV. And so, that's something we really need to think about, I think, as we move forward.

And then, this is probably the biggest part, biggest caveat I would say, is that the baseline consumption shape that I've showed here is just 2015. We haven't incorporated any of the variation that could happen or the changes due to the economy, or behavior would be another thing that we need to incorporate. So, that hourly forecast is going to be really critical for us to include this peak shift in.

So, that's kind of the bulk of my presentation here. Any questions? Comments?

CHAIR WEISENMILLER: I think probably the interesting issue to really think about is, again, just trying to set priorities on where we're going forward. Certainly, we need to be doing this. The question is sort of the peak versus the average or that whole spectrum in between.

And I suspect, for like the NERC stuff, you need to think somewhat on -- spend some real attention on the peak question and on a lot of other things we're looking, procurement or transmission. You know, a lot of other things are going to be much more driven by what's more expected case. Right. And so somehow as you -- then which, again, if we really decide we really have to get the peak right, then you're going to have to take into account the solar production fall off and/or how much -- I think, the historical metric is 1 in 10. We know climate's changing. You know, certainly some of the stuff from Scripps indicates that. You know, say in Sacramento, you've got a real shift up generally on the temperature. And the sort of all-peak is sort of temperature -- the deltas are reducing going forward and that certainly has other implications.

You could discover a lot of those transformers are blowing. And between that effect and the EV effect, you know, the charging effect.

So, again, I think we probably need to be thinking pretty consciously what we need to do on peak but, at the same time, trying to really push the sales part forward, too, on average.

COMMISSIONER MC ALLISTER: Yeah, I guess I'm wondering, well, what you asked about the data from the ISO, you know, DR pilot. I mean, it seems like to me key variables here, sort of targeted energy efficiency storage, demand response, really on the demand side. Because it seems like those resources are going to be really key to have data about so you can sort of unpack what's really going on in any given area.

So, I want to just encourage, again, data generation, whether it's at the ISO, on the wholesale side, or with the PUC and the IOUs on their retail demand response. Get data from that in sort of as much detail as is reasonable to be able to, you know, translate it over to the different elements of the forecast. Because I think those effects are likely to be pretty sizeable.

MR. GARCIA: All right.

COMMISSIONER MC ALLISTER: Thanks, Cary.

MS. RAITT: Thanks, Cary.

Next is Hongyan Shen from Southern California Edison.

MS. SHEN: Thank you, Commissioners. I'm really honored today to have the opportunity to present the simple analysis SCE performed early this year, and share it with both CEC staff and the CAISO team in terms of the bringing more recognition to the peak hour shifting pact, our peak forecast.

As I enjoyed the morning discussion about how to improve our solar PV forecast, I really realized that as we bring more common recognition of those challenges on the solar PV forecast, it's also very important that we help to bring the common stating on the peak hour shifting pact. As we gain that common understanding, I think it really provides us more room for the future improvements, you know, on the peak forecast.

So, on that note, I really wanted to thank both CEC staff and the CAISO team for their openness in working with us and really engaging through the whole process to help us all gain that common recognition. We really feel that we were supported through the process.

So, let me just jump into the presentation. So, we, SCE has observed up to now that our annual peak hour has really shifted. If we look a few years back, in 2012, which is the orange line, and we did see that our peak hour is hour 16, the 4:00 p.m. in the afternoon. So, a few years ago we wouldn't even bother to think about, you know, where is the next year's peak hour. But things develop rapidly.

So, by 2015 we already saw that our peak day load profile got shifted. And as we recognized that our peak hour, highlighted by the green line, it's been shifted to hour 17. So, that's kind of the intuition we gained from the empirical observation that we need to build in some consideration of this annual peak hour shift.

To help people understand, you know, how we are looking at our annual peak hour being shifted, we really just looked at, you know, how much solar, the increasing solar capacity we're getting from the system could bring that impact to our peak hour.

And this illustrated example starts with, you know, our projected initial demand, which is highlighted by the upper yellow area. And that, you know, our initial demand, without factoring in the incremental solar PV capacity to our system, you know, does have peak hour of 16.

However, if we assume that we're going to bring additional 4,000 megawatts of solar capacity onto our system, we actually would be looking at the new area that's covered by the green area and, you know, that curve would yield a peak hour of hour 18.

So, how do we analyze this peak hour shift? We have developed the next two scenarios to help look at how the peak hour being shifted easily, with the significant amount of solar PV adding onto our system.

So, the first scenario simply looked -- we were simply looking at adding another 1,000 megawatt solar PV capacity to our system, from what we look at today. And just with that 1,000 megawatt solar PV addition, by factoring the expected hourly solar generation that we would expect on the peak day, we are looking at our peak day load profile getting shifted and we'll have a peak hour of hour 17.

And if we're looking at our system continue to add on more solar, at some point when we get 4,000 megawatt more of solar PV capacity, we can easily see that our expected peak day solar generation, you know, definitely is increased. And with that change, we would actually get an hour 18 as the annual peak hour.

So, after recognizing that our peak hour can be easily shifted just with simply the solar PV capacity expansion, how do we analyze the impact that we may get from the peak hour shift on our peak demand projection?

As we looked into the peak hour being shifted later, we're really seeing that the peak reduction that we will get from the incremental solar increase would be reduced as the peak hour shifts to hour 17, even 18, the more later hour. The peak reduction we will get from the additional solar PV generation could be very different.

So, if we were to look at year 2025, for example, based on SCE's peak demand analysis, we would be looking at, you know, in year 2025 SCE would already be getting hour 18 for the annual peak hour. So, based on the typical solar generation profile, our peak hour solar reduction we'll be looking at is, you know, what we call this peak impact factor is only 10 percent.

Versus if we assume the peak hour continue to be the same, hour 16, the peaking impact factor could be much higher, 40 percent.

So, that produced a big difference in terms of the projected solar peak reduction we will be factoring in our peak demand forecast.

So, we just did some simple analysis, applying the different peak impact factors to the 2015 IEPR forecast. As we can see, that our SCE planning area peak demand could differ by more than 1,000 megawatts by

2026, if we were to apply different solar peak impact factor based on SCE's analysis.

So, we recognized, sort of the simple analysis, that factoring in the peak hour shift impact is very important. And hope, through this simple analysis, that we also gain some confidence that, you know, applying this impact in factoring our peak demand forecast isn't necessarily rocket science. Really, I think, essentially what we need is extend our peak analysis to include some peak day hourly profiles so that we can examine the hourly conditions and tie that to the corresponding solar hourly generations.

And I think the future, as Cary highlighted, there are a lot more challenges in terms of factoring in other factors that will impact our hourly load as well, including electric vehicle charging load and tier impact. But I think with -- you know, with the improvement of being able to start with a simple hourly analysis and factoring this peak hour shifting fact, it's a major step.

So, that's my presentation. And if there's any questions, feel free.

COMMISSIONER MC ALLISTER: Could you go back to the previous slide, and maybe we'll come back to this one but -- so, could you -- maybe I'm missing something here, but is there some reason for that discontinuity between 2021 and 2022?

MS. SHEN: Yeah, so what you see here is based on SCE's analysis. In our peak forecast we factored in both solar PV projections, and as well as our anticipated EV load increase in the future. So, both would contribute to our future peak shift.

And starting around 2022 time frame is when we expect that our peak hour will shift further, from being hour 17 to hour 18. So, because of the shift, the solar generation contribution to the peak reduction would be much reduced.

COMMISSIONER MC ALLISTER: Okay, so that's sort of like it goes from, you know, 7:29 to 7:31 p.m. and --

MS. SHEN: Right.

COMMISSIONER MC ALLISTER: Or, hour 18, sorry, so 5:29 to 5:31.

MS. SHEN: Right, 18, yeah.

COMMISSIONER MC ALLISTER: And there's less solar an hour later. Okay, so that seems like that probably ought to be smoothed out a little bit in how you specify the analysis there. Yeah.

And I'm assuming on the next slide that's a similar thing that's going on?

MS. SHEN: Yes, yes. And that's a factor of, you know, I think with the future refinement in our forecast, if we build more confidence in the future EV projection, and TOU impact analysis, with the integrated impact that we can bring together, if we are looking at our peak being shifted from a certain hour to a later hour, around a certain time, the gap you see here is really a timing in terms of our integrated analysis, the result of that.

If we were looking at the peak hour would be shifted to the later hour much early on, then that gap could be created at a different time.

COMMISSIONER MC ALLISTER: Great, thanks.

CHAIR WEISENMILLER: A different question. So, looking at the net metering number, or where people are versus the net metering cap, obviously, SDG&E's closely approaching and if not there, PG&E is right on their heels, and Edison is lagging that.

So, part of the question is can you see this effect better at any of the specific areas in your service territory? You should be the most muted on your shift compared to the other utilities, you know, in knowing some of the POUs which, again, could easily be shooting past the net metering cap?

MS. SHEN: Maybe I'd like to get a rephrase of the question?

CHAIR WEISENMILLER: Okay. ISO has said, gee, you can see in Fresno. Okay, and you're looking at an overall system. And I'm saying, wait a minute, your system has the least amount of solar behind the meter on it. So, have you tried to zoom in on any specific areas, which have a lot of solar in your system, where these effects might be more easily displayed?

MS. SHEN: Yes, I believe when we look closely at the local areas across our territory, we will be looking at different situations. And as ISO pointed out, Fresno is a great example. And we have dramatic different geographic areas across our territory. The inland areas could be having very different, as you can see in the coastal areas, especially in the future solar PV growth.

CHAIR WEISENMILLER: Yeah, I guess I'm looking for where it is now in your data. I mean, the one thing that happens in these sort of models is essential limit theorem. Is that you've got a lot of the particular assumptions are off. But if you have enough -- but a lot of those are in offsetting ways.

Now, obviously, if we're all talking just about adding more and more preferred technologies, then it tends to be one directional. But again, if you ever go through, say, an Edison production cost model and match history versus what the forecast was just about every -- you know, a lot of the assumptions are off. But again, they tend to offset each other in ways that the forecast can still be pretty good, even though a particular power plant is pretty bad.

So, again, we have a particular effect here, but there could easily be offsetting effects going on. So, again, I'm trying to say -- it would really help us if you could say here, in the Edison service territory here are some specific examples, local area wide, where you could really see this effect big time.

MS. SHEN: Sure. I think, Commissioner Weisenmiller, you just highlighted the next challenges we will face, which is getting a better handle on the more granular level forecast.

And in our view, I think we're looking at how to combine the top level, the system level forecast and bring up more bottom level information. And, hopefully, we would be able to take advantage of the more granular level information and, at the same time, benefit from the high level forecast if we're trying to be more consistent. And that's what we'd like to work with CEC and the other stakeholders in the near future to tackle those granular level forecast issues.

CHAIR WEISENMILLER: Okay, great, thanks.

MS. SHEN: Any other questions? Thank you.

MS. RAITT: Thanks.

So, that concludes the panel. Next, is there any stakeholder responses or comments, if folks wanted to come to the podium and identify yourself? I guess not.

Okay. Well, we can go on to the Long-Term Forecasting of Hourly Loads. If our panel could come up to the tables, we have seats for you all.

And thank you, again, for our speakers.

The first is Chris Kavalec, from the Energy Commission.

MR. KAVALEC: Yeah, Chris Kavalec again, Energy Commission Staff. I'm going to talk about our staff's plan to begin to forecast hourly loads in the long-term for the 2017 IEPR forecast and beyond that.

Also, in this section of the workshop we will have Alan Sanstad, of our expert panel, talk about some of the issues and considerations involved in forecasting hourly loads.

We will have Bob Emmert, from CAISO, where they use a short-term hourly and peak forecasting model that could conceivably be used for long-term hourly forecasting. And it at least presents a possibility as a platform on where we can house our estimated models.

And San Diego has done some impressive work on forecasting hourly loads and they'll talk about that.

So, right now, the situation is that we produce, for our long-term demand forecast we produce annual totals for sales, and net energy for load, and for consumption and for peak demand.

However, as we know, long-term projections at the hourly level are becoming more and more important for resource planning. So, people, resource planners are now understandably interested not just in the peak of a day or a month, but they're interested in a ramp up period, and midday loads, the so-called duck curve phenomenon.

And as we've just heard, there are demand side factors, including PV and electric vehicles that are likely to shift the peak hour to later in the day. And you can't really do a full analysis of this unless you have an underlying projection for hourly loads in the long term.

So, our goal is to develop a model that projects 8760 hourly loads, ten years out for a given geography. And the way that we'll go about this is we'll develop a sort of business-as-usual projections that account for economic and demographic changes, changes in sector shares, other factors that may affect the daily load shape.

As an example, if industrial energy use continues to remain flat or decline, and industrial has a fairly flat load shape, while residential and small commercial continues to grow, you’re going to get a peak year load shape out five, ten years from now. So, that has to be accounted for, along with the impact of demand modifiers.

And then, we will adjust this business-as-usual case to account for our load modifiers, PV, electric vehicles, AAEE, demand response on the demand side, and TOU pricing in the residential sector, which will become much more common.

COMMISSIONER MC ALLISTER: Can I -- I want to ask a question, sort of following up on the last panel. So, it seems like we’ve been talking a lot about PV, so particularly with PV it seems like this hourly binning maybe, sort of creates a possibility that answers we get might be actually pretty different based on, well, certainly geography, but even just the particulars of a given analysis. Like, if it happens to be at, you know, 5:59 versus 6:01, well, that’s in a different hour and, therefore, it looks different. But, actually, it’s pretty similar. So, I guess that ramp coming right as the sun is setting makes the -- sort of gives a lot of important results and those details right around that moment being pretty important in swinging your answer, you know, broadly one way or the other.

MR. KAVALEC: Yeah.

COMMISSIONER MC ALLISTER: So, is there any way to sort of improve upon this hourly binning with respect to, you know, when the peak moment actually happens versus which hour it's in?

MR. KAVALEC: I would think so, yeah. Right offhand I can't think of a simple way. But I believe there certainly is a way to smooth out that transition so you don't get that abrupt change.

COMMISSIONER MC ALLISTER: It just seems odd that you get that -- you know, it's not intuitive that you get that big of a difference just with a sort of a gradual switch from one year to the next. Then all of the sudden the flip switch is in a different hour and then all of the sudden you've got different planning assumptions, right.

MR. KAVALEC: Yeah, so some sort of way, formulation to transition this is -- or we could go 8760 times 60 minutes.

COMMISSIONER MC ALLISTER: Yeah, no, I'm not advocating for that, just to be clear. But maybe, you know, some way of dealing -- since a lot of -- the driver of many of these discussions we're having is when the sun sets and when load peaks, right. So, that is more -- you know, an hour is a pretty blunt instrument for talking about that.

MR. KAVALEC: That's right.

CHAIR WEISENMILLER: Well, you recall the ISO dispatch periods, they're shortened from hour to -- much shorter times. Not that Chris even wants to think about a 5- or 15-minute forecast.

COMMISSIONER MC ALLISTER: Yeah. No, for sure. And this isn't, you know, a dispatch model so that's okay. But if it drops -- and to the extent it drops investment, you know, and, oh, gosh, you know, it's in the later hour so the peak is way down here. When actually, in fact, relative to the true system peak it's maybe not that bad, you know.

MR. KAVALEC: You'd get a funny looking forecast.

COMMISSIONER MC ALLISTER: Yeah, exactly.

MR. KAVALEC: And it's not warranted, yeah.

COMMISSIONER MC ALLISTER: Anyway, I just wanted to bring that up and see if we can find an analytical approach on it.

MR. KAVALEC: Yeah, it's a great point.

Okay, so we're in the middle of a data

rulemaking process. And the conclusion of this process should be early next year. And by that time we'll sort of know what we'll be able to get ahold of in terms of metered data to support these models.

So right now, we have to rely on the hourly load data that we have, which is mainly the CAISO EMS data to project hourly loads.

So, our first version of this model, in other words, will forecast hourly loads at the TAC level. And the later versions, once our data and negotiations are resolved, would use AMI data in some form to estimate models at a more granular geography, and by sector, and so on.

But I should point out, just doing an hourly load model for the PG&E TAC area, as a whole, is a big project. I mean, this is not a simple -- projecting hourly loads out ten years is not a simple project. So, it takes a lot of thought, it takes a lot work. So, anyway, that's where we're headed.

And so, the first version of our model we're proposing we would estimate using loads that are reconstituted. Meaning, we would be adding back in photovoltaics and other DG to get a measure of total end use demand, regardless of generation source.

And this would be specified as a function of economic, demographic, weather, other characterizing variables, as well as lagged hourly loads. So, you see it in equation form there, hourly loads as a function of the economy, and weather, and sector characteristics, lag.

And I believe Alan will talk a little bit more about considerations of what variables should be included in the estimation process.

One thing that gets tricky here is that you'll end up with variables with different frequencies. So, you'll have daily or hourly weather observations, but then you'll have quarterly economic and demographic observations. And then monthly observations in terms of things like sector shares.

So, the question is how to combine all these different time periods. And I believe Alan will address that a little bit, too.

So, the later model versions, as I mentioned, once we get the hoped-for abundance of data, we'll be able to do hourly loads for more granular geography, down to the local areas, and do hourly loads by sectors. And even groupings within the sectors.

One model we've looked at, that was estimated recently for studying DR potential, was done by Lawrence Berkeley. And we asked them to be on, listen in to the workshop today, so they may have -- they may be able to share with us some sort of overall general comments on their experience in putting together an hourly load model.

And I believe Lawrence Berkeley was also able to incorporate end use load shapes within their hourly load forecasting model. And that's something we would aspire to, as well.

Oh, I guess that's it. Okay, so we're hard at work on this now. We're looking at different estimation processes, playing around with the data. And as I said, our plans are to have hourly load models for the TAC areas, for the 2017 IEPR.

COMMISSIONER MC ALLISTER: Great, thanks. This is very exciting. I don't know if all of you get charged up about this, but this is really, so clearly a step in the right direction for where we need to go long term. And data issues, we're going to struggle with those. But, you know, once we get to a certain point we can build on that and it's all -- you know, it's iterative. So, extremely supportive.

And just also wanted to point out this is the year that -- the IEPR update is the year we have the luxury of having this conversation without actually having the burden on the team of doing the whole forecast. We can really focus on the methodology. That's why we're here today. And I just want to make sure we kind of appreciate the urgency of kind of getting to a good point by the end of this cycle. Because next year, it's going to be upon us to actually do the new forecast. So, anyway, hopefully, everybody can put on their best thinking caps, and get in comments, and help this process get to a good conclusion. Thanks.

CHAIR WEISENMILLER: No, thanks. I was just going to say one of the groups to really pull in, too, at least when I'm looking at my ISO Today app, at the net demand chart, there is an attempt to go from actual demand to net demand.

And it would be good to understand how that's done and the basis for that. And if, again, we can get anything useful out of that modeling or thought process, right.

MR. KAVALEC: Okay. Okay, I'll then turn it over to Alan, from our expert panel.

MS. RAITT: Just one moment.

MR. SANSTAD: Thank you, Chris. Good afternoon, Commissioners. I'd like to thank you for the opportunity, and Chris, for the opportunity to participate today.

I'm here, representing the outside expert panel that's been working with Chris for several years on methodological issues. It's led by Hill Huntington, an economist at Stanford. Also includes Jim McMann, who's an expert on end use energy analysis and efficiency analysis. Marc Jacquard, who's a specialist in integrated economic and technological modeling at Southern Frasier University in British Columbia, and me.

I'm particularly filling in for Hill today, who's in China. So, Hill is also our panel's expert on statistical and econometric matters. Another way of saying that is that I'm not. So, I'm sort of the economists call an imperfect substitute.

But I want to hit some of the high points, conceptually, of our initial thinking on how to approach the system level hourly demand modeling.

So, a little bit of context for this. Traditionally, and for the most part now, and I'm painting with a broad brush, and this is having to do with utilities around the country, long-run hourly demand forecasting has been conducted subordinately. It's an imperfect term to monthly or annual forecasting. By which I mean a long-term ten years, monthly or annual forecasts will be developed and then filled in. If it's filled in for annual and then filled in for monthly.

And then there will be separate, sometimes, engineering models of hourly demand that will be added to it, connected to it in some -- calibrated to it.

So, this approach, this modeling architecture works both for pure econometric, strict econometric approaches or the modern, what's now called hybrid econometric and end use modeling. So, yeah, the two levels are linked and calibrated, but not fully integrated.

So, what we're talking about here is sort of fully empirically-based, dynamic integrated estimation of the system model hourly loads out a long time. So, this is state of the art. And what I mean by that is something specific. State of the art, the models, you know, and techniques I'm going to talk about are standard. But the strategy and approach seems to be sort of new.

There's some experimental work, academic work, and some applied work, for example in ERCOT, going on with direct long-term estimation, empirical estimation of hourly loads. But it's still, and I think as far as shorter term innovations in forecasting, we're going to hear later in this session from our colleagues at ISO and San Diego.

But this, I think, is a new step and will be very valuable if it works out.

COMMISSIONER MC ALLISTER: That would be --

MR. SANSTAD: Any East Coasters? I do, I hit the down arrow.

COMMISSIONER MC ALLISTER: Oh, it’s not okay.

MR. SANSTAD: To bad about the Warriors, eh?

(Laughter)

MR. GARCIA: Don’t hit those down arrows.

MR. SANSTAD: Down or right to go -- left or right, that may be the problem.

Okay, so the general approach, it’s a linear model, what’s called panel data linear regression. Panel data just means, okay, it’s a combination of time series and cross-sectional. The cross-sections, in panel data, means different subgroups. In this case, the TAC areas are subgroups. And so, you’re following sort of two dimensions, times and cross-sections ahead.

The dependent variable is system level hourly load. And our thinking is that the model we’re going to have, as Chris mentioned, we’re relying on ISO data, ten years’ of data to estimate the model on seven years’ of data. And then test it out of a sample on -- you know, we have the sample. On three years before going to forecasting.

So, this looks like an exact list. It’s not.

There's devils in the details for each of these. But in general, I want to show you what we think about it inside.

So, first of all, Chris talked about weather. So, you know, obviously the weather temperature, and humidity, or cloud cover variable are critical factors. You know, there's daily temperatures, lag temperatures, previous days. Depending, we're still talking about it, as Chris said, the intraday structure of the model.

So, the previous day system and for the given hour to monthly and every fixed effects, which are sort of akin to dummy variables, but they capture the effect of -- the specific effect, and it's non-random and non-changing of those factors.

The electricity prices, we'll start with average rates. Going forward, we would try to get more granular and include more detail on the tariffs and so forth.

So, as Chris mentioned, we have quarterly -- we have quarterly data on macroeconomics sector outputs, industrial classification sector, employment, as well as demographics. We'll also plan to incorporate monthly sateral (phonetic) load shares. The sectors here meaning the end use sectors.

And finally, an important point I'll come back to, is some way of representing indices or proxies is deliberately vague. Some manner of representing the effects in history of efficiency-promoting policies, programs and regulations.

Now, way of saying -- to back up a second. If you didn't put these in, obviously, your model would pick up whatever effects are there, you know, because they're in the data.

The idea is to, though, somehow estimate the model with those historically, explicitly spelled out. Because in the forecasting simulation those are going to be drivers of very critical interest.

So, there are a lot of issues on something like this. First of all, I didn't put it down, but the 800-pound gorilla is the data, itself. It requires -- it's very data-intensive, as the gentleman from NREL pointed out, for this kind of model, a lot of data. There should be a lot of data. But putting it all together, the weather normalization, which in this case is simply defining what the weather independent variable should be, how it should be configured. There are also issues about nonlinear effects of weather in this kind of model. There are ways of dealing, taking account of some of the nonlinearity.

So, as was pointed out by Chris, too, there's the use of the mixed frequency data is an issue. This is in the business and academic econometric. This is now something for whole literature, which I don't know anything about. Though there are ways of dealing with it, they are more complicated and may not be actually practical in the current generation of commercial statistical software.

So, our recommendation is always to start with ordinarily squares and test for heteroscedasticity and autocorrelation. So, forgive me if you already know this. These are fancy words meaning something very intuitive. It has to do with the nature of the randomness.

So, the beauty of all this is under the right conditions it produces estimates which are unbiased, which is accurate, and also what's called efficient. So, the smallest variance, roughly speaking.

So, that depends on certain assumptions about the nature of the uncertainty. In this case it would mean the uncertainty, roughly the uncertainty associated with different observation units, with respect to model here, the TACs is the same. Well, it's not going to be.

And the other thing, in the time series model, is our autocorrelation, which is events at one time provide no information about events the next time. That's obviously, also not true.

So, there are standard tests for detecting these things. They will be present. There are ways of correcting for them. There are much more complicated ways of estimating a model like this. We would rather not go there, at least initially, unless it's absolutely necessary.

One questions that we've discussed is using load per customer rather than system load. The load per customer, that's a common specification, for example, end use demand modeling. It's not clear what advantage -- there may be statistical advantage of doing it in terms of the fit, having a log on the left-hand side. But it's not clear, I mean in this case, what you really want to know is the system level load and representing energy efficiency.

So, this is the question of how you represent energy efficiency, sort of in the aggregate, whether you have aggregate information or bottom up information is very hard. It's been the subject of DAWG workshops, now, for five years, understanding how that's done in the CEC's forecasting model.

Several years ago, the PUC sponsored a project. It was called Macro Consumption Metrics for Energy Efficiency. It was a project to estimate the effects of energy efficiency from California programs, purely econometrically. It had two econometrics teams working on it.

And, you know, as sort of a proofs of concept you can do it. It's hard to do. The estimates are very noisy. So, this is definitely -- it's both a priority and will be a huge challenge. But it's something of sine qua non for this because of the applications of the model.

So, forecast, so this is, loosely speaking, be a hybrid. So, with what you could do, you have to have the driver, you have to have forecasts of the drivers, right, the independent variables.

Conditional on that, this is actually a statistical forecast. Speaking to Commissioner McAllister's point about uncertainty, an advantage of doing this kind of modeling is that you can explicitly quantify the uncertainty, right, you get standard errors.

One thing I mentioned -- or, sorry, forgot that point. So, even in the presence of these problems, it still yields unbiased estimates and the parameters. The problem is the variance estimates can be biased. And that matters. To what extent, we'll find out. For forecasting it may not matter as much because when you're doing simulations out very far, those variance errors might be dwarfed by errors in, you know, the main inputs, like GSP. But we'll see.

So, I think this -- doing this offers an advantage in terms of both accuracy and uncertainty quantification over methods, like those I mentioned initially, where you're putting together the information from disparate sources, so which may not be statistical.

But there's -- obviously, there will be, there's unavoidable very considerable uncertainty in making these kinds of projections at all. It brings to mind a project that we're working on at LBL, studying the accuracy of long-term load forecasts by some WECC utilities in the middle of the 2000s decade. Not including, actually, the California utilities.

Very sophisticated procedures for doing these forecasts. It was, initially, an actual experiment because these happened to be done a few years before the economic crash. And that turned out to introduce in most -- for the most utilities, you know, very significant forecast errors, as you would expect.

So, there's not only lots of uncertainty, but there's a hierarchy of uncertainty.

So, one thing about this, and it has to do with this issue of granularity, which as the Chairman mentioned, and we all know, is one of the goals, and big sort of goals across a lot of these development projects.

One thing about focusing on aggregates is you can often do a better job of projecting an aggregate than a disaggregate, right. Especially here, when we're going to have a lot of data and be able to take account of it.

Chris mentioned that if all goes well, this would be a first step towards more disaggregately-focused modeling of this kind. And, of course, as the AMI data, we hope, becomes available, taking that into account somehow and building up from the bottom up, the available empirical information.

But it's also worth pointing out that the more granularity, it generally comes with a lot of uncertainty. It increases the uncertainty, especially when you're projecting out long time periods.

My personal view is there's a pervasive illusion of precision problem in energy problem. It's actually getting worse. But, you know, it's everywhere. Not the single thing that's happening here.

And it's a great deal of detail in models, if you don't have the empirical information to ground it, which very often is not available, then it's really not clear what you're getting. How to interpret what you're getting.

I have an example, a paper I recently reviewed, had agent-based modeling. Certainly not the NREL people. I thought what they're doing is very great. But it was an agent-based model of residential electricity demand in California and the effects of dynamic pricing.

So, they have 10,000 agents representing California consumption. That's great. Okay, but what they have to parameterize their behavior and their technology choices were statewide averages, right. So, basically what you have in this model were 10,000 identical agents.

Now, why that, you know, is better is not at all apparent. You cannot -- you can't get something for nothing in getting granularity, if you don't have data.

Be that as it's said, I think, again, back to the point that this would estimating a model with a lot of data, at the right level of observation, and I think will be very valuable, and a first step toward addressing a lot of the policy needs. Thank you.

CHAIR WEISENMILLER: Now, I think last time we talked, obviously, it was on disaggregation more in terms of, you know, smaller -- you know, going geographically. And at this point we're trying to geographically and temporally, both.

MR. SANSTAD: Right.

CHAIR WEISENMILLER: And so, basically, you're right, trying to figure out how to do it in a meaningful way.

Obviously, one of the things which will be useful, I think, is we do statewide, at some point the ISO or the utilities crank it down, or we do it down to substations. And at least the process should be more transparent. I'm not saying that, you know, anyone has any brilliant ideas on how to do it better, but at least I think we need to get more public exposure to the process of doing that.

MR. SANSTAD: Right, and also --

CHAIR WEISENMILLER: And similarly, the temporal side.

MR. SANSTAD: Certainly. Also, I'm a little speaking out of turn, to an extent, because I'm not involved in the details of these processes. But I also think understanding what you're using these for, you know, and how much the error matters is a critical thing.

CHAIR WEISENMILLER: Yeah.

MR. SANSTAD: So, you might have a lot of end use -- you know, spatial detail and so forth on current data. If you're projecting out ten years, okay, well, what are you getting? If it doesn't matter, then that should be built into the process. By not mattering I mean that there will be continual updates between now and ten years' from now, right. So, it's not like you plant a stake in the ground and then your forecast, and then come back to it.

CHAIR WEISENMILLER: Right.

MR. SANSTAD: So it would help, to an outsider, at least, it would help a lot to understand sort of the relationship between the increasing granularity and the updating of the forecast over time, you know, and how the uncertainty sort of gets managed then.

Because the forecast doesn't have to be exactly right out ten years, right?

CHAIR WEISENMILLER: Right.

MR. SANSTAD: So, I don't understand the details enough to know, but I think that would help sort of, to some extent, think about how to deal with the uncertainty associated with the granularity.

CHAIR WEISENMILLER: Yeah, we've actually, the last couple of times, distinguished between what we're doing in a local capacity area and broader scale, and being somewhat more conservative. Because, again, not only are we doing the sales, but the EE, and there are a whole bunch of things that are being disaggregated down another level, and no one’s quite sure, the more disaggregated you get, you know, how comfortable -- or what the uncertainties, inherent uncertainties are.

MR. SANSTAD: Right, but --

CHAIR WEISENMILLER: But you’re right. I mean these are -- these will be updated at least every two years, if not every year.

MR. SANSTAD: Right.

CHAIR WEISENMILLER: And, hopefully, there’s more and better data. Obviously, the thing that we’re struggling with is that, you know, we’re talking about, you know, as opposed to classic econometric model or regression models, we’re talking about fundamental things. You know, solar, right, PV. If you just ignored it and did a regression, you’d be really wrong.

Now as it is, building it in we’re capturing more of that and, hopefully, when we get to this question of do we upgrade this substation or that substation, you know, that somehow we’re getting closer than we would be. But again, it is -- the more we get into those -- anyway, the more disaggregated we get, the more we have to be worried -- as you said, a precision question and what does it really mean, what we’re really trying to capture, some of the policy tradeoffs particularly at that disaggregated level.

COMMISSIONER MC ALLISTER: At some point, and I'm not sure this is a question for you, but it occurs to me, you know, we're talking about, oh, we're going to get so much more data, and I'm certainly preparing to that. And on the existing building side, you know, absolutely I think we need more and better data, and to enable not only ourselves, and targeting policy, and developing good policy, but also out there for the marketplace, right.

So, we're going to get these massive flows of data in different directions. And in our case, I mean, it's going to require a pretty serious IT project to like, okay, where is this data flowing into? Where is it sitting? How can it be managed and curated over time? You know, I mean you've got all the quality issues you've got to work through. And our team is thinking about that and, you know, I think has an approach.

But I guess, you know, I think sort of making sure we get good advice just on the nuts and bolts of what big data tools are, you know, appropriate for 2016 and beyond.

MR. SANSTAD: Absolutely.

COMMISSIONER MC ALLISTER: You know, how the sort of, you know, web-based tools can be best taken advantage of, how standardized data transfer protocols can be brought to all of this.

MR. SANSTAD: Absolutely.

COMMISSIONER MC ALLISTER: I mean, there's just a lot of real nuts and bolts, IT questions, that are fundamental to get right to even begin to put this tool together, right?

MR. SANSTAD: Your point is extremely well taken. It's not just IT, but it's sort of data management.

COMMISSIONER MC ALLISTER: Yeah, exactly.

MR. SANSTAD: I have another anecdote. Over the years, working on end use policy, especially, California, people around outside California, always say, well, California has all this data and we can do so much, right. And they already call you, you have this data. And California does have a lot of data, but the data tend to be in different places, under the control of different entities, not necessarily consistent and whatnot.

So, when you actually -- when you're in the trenches, you don't have a lot of data, you have a lot of confusion.

So, that kind of organized systemic effort, you know, both on IT issues, but on sort of conceptually, and doing that from the get go, say, is hugely important, I think.

COMMISSIONER MC ALLISTER: Yeah, and I think we haven't really talked directly about that. But I think in the subsequent workshops we're going to have to get into some of those issues.

CHAIR WEISENMILLER: Yeah, I sort of flagged those. So, again, in terms of the basic narrative arc, you know, today's issues are things which, as we were adopting the last forecast, you know, after people came running in saying, well, what about this, this and this, and it was like, okay, we have five hours. We'll hunt these and, basically, they landed here.

Now, the whole question of what are we doing on 350 and 802, which is a huge, huge effort that's coming up later next month. And, you know, we'll go on for the next --

COMMISSIONER MC ALLISTER: Couple of years.

CHAIR WEISENMILLER: -- decade.

COMMISSIONER MC ALLISTER: Anyway, I just wanted to bring that up because I think it was sort of like hanging out there, unsaid.

MR. SANSTAD: You're right.

COMMISSIONER MC ALLISTER: And, you know, we are getting that conversation going and mostly in subsequent workshops.

CHAIR WEISENMILLER: Yeah, yeah, thanks.

MR. SANSTAD: Thank you.

Do you want to -- I don't want to extricate my own disk because I might blow it up.

MS. RAITT: Got it.

MR. SANSTAD: Thank you.

MS. RAITT: All right, thanks.

COMMISSIONER MC ALLISTER: Thanks, Alan.

MS. RAITT: So, next is Bob Emmert from the California Independent System Operator.

MR. EMMERT: Well, good afternoon. Again, I'm Bob Emmert, Manager of Interconnection Resources at the California ISO. And I appreciate this opportunity to come and give you a very, very high level overview of our, what I call either our short-term or mid-term forecasting process, as well as the tools that we use within that process.

This came out of a discussion we had at a JASK meeting a few weeks ago, where I was talking with Chris about where they were going, where you guys are going related to your forecasting to get to the hourly forecast. And just was talking about what we did and, you know, the capabilities of the model that we used and so forth, and he asked me to do a presentation on this.

So, I'll just be kind of giving a very high-level overview of our forecast process, and as well as the tools that we use to do that, so that you kind of get a feel for an option that's out there for you to accomplish some of the things you're trying to accomplish.

So, just a little bit of background, the tool that we use is used for our -- the basic platform is used for both our day-ahead forecast, as well as our short-term or mid-term forecast we use in our summer, which has now evolved into an annual assessment, where we do a one-year-out forecast.

And we don't do a ten-year forecast. We've got the Energy Commission. But most states don't. Most of the ISOs around the country don't have that kind of a setup. So, they are doing their own ten-year forecast using this tool.

So, this tool is -- you know, has a lot of capability to do whatever type of forecasting you're really looking to accomplish.

You know, from our perspective, one of the benefits of using this vendor forecast tool, from our perspective it's a proven platform, with ongoing improvements. Where the vendor that we have chosen has customers around the country, including Canada and around the world. So, it's a very well-proven out platform and customers are always working with them to come up ways to improve it. So, we see some improvements from time to time. Not so much in the basics of the forecasting, but in just kind of the interface with it and some tools to help build the forecast you want to be building.

They provide a lot of vendor expertise. Whenever we get -- when we got into the initial model build for the forecast that we work on, as well as the day-ahead forecast, and also when MRTU came on, and we moved from hourly to 15 minutes, and now EIM every five minutes, the optimizing of that, they have provided a lot of expertise to help us.

You know, Alan, I really appreciate everything Alan was saying. You know, that's the kind of expertise that comes in and helps us to make sure that we're thinking of everything. Because, you know, when you have a model or a platform such as this, some of those things you may not have the expertise in every area, so you need someone to come in to make sure you're doing everything right, and not just making assumptions that, hey, I've got a really good MAPE on this forecast so, therefore, it's a great forecast. Which is something I learned very quickly in my experience, a good MAPE doesn't necessarily mean a good forecast.

We have a long-term vendor support from them, then, on an as-needed basis. We don't use them very often, but when we have a project that we think we'd like to have some additional expertise brought in, we use them for that.

Again, like I said earlier, it's the same basic platform for all the ISO forecasting needs.

And one of the things we also have found is the vendor has developed a user group. That we get together on an annual basis, and it's ISOs from across the U.S. and Canada get together and talk about our forecasting processes. And we share best practices. Some of the real benefits when someone comes in, like the New York ISO came in one time and gave a presentation of some work that was some very detailed work he was doing in a particular area of their day-ahead forecast to improve their forecast, and talked to us about that. And we were able to glean something that we could actually use in our mid-term forecast process.

So, you know, improvements of other ISOs, or users are using can kind of cross-pollinate each other to help everybody improve. Which really helps foster a process of continuing improvement. So, I really saw or we continue to see a lot of benefit in just participating in that user group, as well.

This is just a very high level walk through of our forecast process. You know, the basic inputs in the model. You know, Alan talked about them all.

One of the things that we just installed this last year was behind-the-meter solar input. And you were asking about that, Commissioner Weisenmiller, about, you know, do we have that data? Well, we got it from you. If we hadn't of been able to get it from you, we wouldn't have that data, so we appreciate that.

But, you know, we have another data in other areas, but that's one component of data we don't have. So, we wouldn't be much help there, but really appreciated, you know, the morning session, talking about how this forecasting process is really working. That is the input that would go into this model. So, the more robust input of a forecast you have, the better forecast you'll have in the end.

You know, some of our models are based on forecasts. So, we forecast based on forecasts. So, when you have a forecast of behind-the-meter solar, your demographic and economic data's a forecast. So, the better those forecasts are, the better your end use forecast will be.

Just to kind of go through this real briefly, we take all those inputs and we put them into our model. We train the model based on the latest inputs. As loads changes, as weather can potentially change, the model has to learn from that. So, we put that information into the model and we train the model every year to get it to the best forecast model we can. That's our base forecast model.

We also take all of our weather data, and our weather data, we start in '95 and have moved forward from there. Mainly because that's when we have relative humidity data from all of the weather stations that we use. And so, we've also felt that was a good way to deal with climate change in that we're using more recent data. So, now that we've got about 20 years of that data since then, we may consider some ways to maybe even shorten that up. But that's something we're just now considering.

But we take all of that 20 years' worth of data and we send it in to a weather simulation model that basically gives us seven different scenarios for each years' worth of weather. Basically, what it does is it just indexes each of those weather years by one day, seven times, so that you have the peak day of the year occurring on each of the seven days of the week. So, it gives us seven profiles that are a little bit different, but all based on the same weather year. So, that gives us closer to 200 profiles when we're all done.

And we take all those profiles, mix it with our base case forecast to get our full range of weather forecast -- or, excuse me, load forecast based on weather for all those various scenarios. And from there, we take it into our probabilistic work and develop our 1-in-2, 1-in-10 forecasts.

This is just a quick look at some components of the tool that we use to show that, you know, there's a lot of flexibility built into these tools to where we can -- we use the regression model to do our forecasting. But we also have used the narrow network model that is associated with this model. You look at the analytical tools, and I'll show you one of them, but there's kind of a list of some of them. This is not the full list, but at least gave you a taste of it and at a size you can read on a presentation.

Under number 3, the multiple-region model analysis, those are the various models we have built. So, within one file, we've got multiple models. So, the ISO modeled a system. We've modeled NP 26, SP 26. Each of the IOUs use as a whole. In a couple cases for PG&E and Edison, we have split those into two components.

So, that's as low as we've gotten as far as disaggregation of those loads, but you can go further. You could go down as far as you want, it's just a matter of data.

And then, finally, under the variable input assumptions this just shows that some of the type of variables that we put in there, we use a base case economic forecast to do our base case forecast. But we also do some scenario analysis around four different scenarios that we get for economic forecasts, as well, to get a better feel for what the potential of loads doing under different economic -- how they actually play out versus what the forecast is.

So, this is one of the tools. This is a scatter pot that demonstrates the correlation between load and temperature. So, being a linear regression model, it likes to see things in a nice, linear fashion. And this curve does not represent that.

But there are tools within this model to help you to build that. And so from that, using the tools within the model to, you know, just take a closer look at this and be able to build these splines, we developed three splines to represent this correlation of load and temperature. And to help us build a more accurate model.

And this is just a quick look at the outcome of it. The R squared and the MAPE here, we feel that our forecasts are pretty accurate. Our errors are pretty low and they continue to be year after year. Each year does have to be trained to get it to this level, but we feel pretty confident with our load forecast.

This is a daily forecast. That's the way we do it currently is we are just forecasting daily peaks. And from that we can come up with our monthly peaks, and annual peaks, and that type of thing.

But just one thing you can't really see very well, but the blue line is actually into the forecast period, where using typical weather, and using the economic and demographic inputs, and so forth.

In the historical portion, you actually have real GDP information, real weather, real loads. And it actually does a back cast. And behind that red line is actually a blue line. So, only in the last year can you actually see some deviation between the back cast and the actual, the loads that we're seeing. So, it matches pretty well.

And this just shows going to an annual forecast. Where Mike Wu here is our lead forecaster, and he built this. In a prior job in Alberta, he did hourly load forecasts for a little bit less than a year out. So, he’s got some experience in doing that. So he, in just a couple days’ period, put together an hourly model using this tool. Where, over there on the left-hand side, you can see there’s a model for each hour that was developed to be able to do an hourly forecast model. This was done pretty quickly. Not going out ten years because we don’t do 10-year forecasts. So, you know, if we were going to do ten years, there’s a lot more that would need to be considered in doing that type of forecast. But just to put the basic model together, he did it in a couple of days.

So, the tool is very adaptable to the type of forecast you want to do. So, we’ve found a lot of benefit in that at the ISO.

And this just gives you a feel for the forecast and the back cast on an hourly basis, where you just look at a particular week and then see the correlation, or just how well the match that the forecast does give you, where the MAPE is 1.32 and R squared is .993. So, building a forecast pretty quickly came out with, at least for that period, a very good correlation.

And so, again, though, this is not a 10-year model and there would be -- you wouldn’t put a 10-year model in two days, but at least the starts of it are there.

And then, this just kind of gives you a feel for the latest forecast we put together. The black line is our historical portion based on actual weather and actual economics, and so forth.

We started weather normalizing back in 2003, so the red points are the weather-normalized load. This model is used to do weather normalization, as well. So, we feel that it's just a very robust tool to do just about whatever we're looking to do in our forecast arena.

Typically, when you're a forecaster, you don't find that your weather is 1-in-2, and to be able to really compare how you're model's doing, you have to do that through weather normalization. But last year was a pretty unique year. On a system wide basis our load was very close -- or, excuse me, the weather was very close to a 1-in-2 year. So, we were able to compare what was our model doing? And you can see from this that our forecast was 47.257. Our actual 1-in-2 peak demand was 47.188. And our normalized peak was 47.167. So, very close to each other. So, this really gave us, I guess, a little bit of pride and some real good feelings that, yeah, our forecast is doing what we think it's doing, And just going beyond the weather normalization we're finding that the forecast is pretty accurate. Again, this is one year out. It’s not ten years out.

So, just to kind of wrap this up, we just wanted to really give you guys some thinking about, you know, what we would recommend and why we think we would recommend something like this. That you would use a similar tool, either the same one or a different one, but it’s the type of tool that we feel could have synergies between the ISO, even the IOUs and the CEC in developing this long-term forecast.

The first one is just to talk about -- there’s more than one option for a proven platform. So, we don’t want to -- we’re not giving you the name of our tool. We’re not trying to advertise any particular one. But there’s more than one to choose from. So, we think that, you know, these tools are well proven out and that shouldn’t be a concern.

The value in participating in user groups with other entities, like entities, we’ve found it very valuable and I would assume that you folks would, too.

Ease of transition into future needs. As I was showing, just building different types of forecasts pretty quickly, and has been very valuable to us. And continuing to use the same platform, regardless of need, even in our market side of forecasts. We continue to use the same platform. Sometimes they’ve been improved significantly where we've gone to the next level, but it's still the same platform. The data input files and everything don't change. So, that's pretty beneficial to us.

And the synergies in coordination between us and the CEC I think are -- you know, we would be able to just talk about data on a common format. We do provide data, now. We could actually provide those files in a format that would just feed directly into your model. We could give you our model files that have our weather data. Well, maybe not weather data. That's something we'd have to talk about. I'm sure we could give that to you, but I'm sure our weather data provider would like a small fee for that. But that's something that could be done and it could be done with our weather data, as well.

It would lead to long-term consistencies between our work that, you know, if you think about it, with the ISO doing day-ahead forecasting, mid-term forecasting, the CEC doing long-term forecasting, where we could develop our own user groups. You know, talking about the type of weather we see in California. What is that doing to our loads? And just have a lot of cross-pollination of what we're learning in our own forecasting processes that could benefit each other.

So, with that, that's pretty much my presentation. And I'll be willing to answer any questions you may have.

CHAIR WEISENMILLER: No, that's pretty good. I mean, without getting into details, obviously, it would be good to start the conversation. I mean, as Chris knows, or I mentioned earlier, just the weather data part, it's like we use publicly available. We're not sure how well they map the utilities, even less certainty on how well they map to what you're doing on the weather side or, similarly, on econ demo is a big question.

I know as we've talked to -- actually, I mean, as part of the Energy Commission for the last 40 years, from time to time it gets into the question of whether it should develop its own short-term forecasting model, since short-term forecasts are much more a function of the economy of weather, than building stock and all the other things we're watching in terms of turnover.

So again, I think there's -- we should continue the dialogue and figure out ways we can do better coordination in this area. And again, if there are particularly ways, again on the data side, we can make some progress there, that would be good.

MR. EMMERT: Yeah, so we appreciate that and would be happy to work through that. You know, we've been doing, I think, a pretty good job of that, but it doesn't mean we can't do better and look for more opportunities, so we'd be happy to do that.

CHAIR WEISENMILLER: Sure. No, I mean, I think, obviously, your agency, my agency, Picker's agency, ARB, all four of us work together pretty closely on stuff. And again, we're looking forward to deepening the relationships.

Chris?

MR. KAVALEC: Yeah, I just wanted to mention that the way I think about this is that really a model, like we're talking about, has two components. It's a bunch of equations for estimation and it's a platform.

CHAIR WEISENMILLER: Right.

MR. KAVALEC: I think this tool would be, could be very useful as a platform. So, we estimate a series of equations, we house them in a platform like this, and it gives us a lot of flexibility in terms of testing the model, looking at model results, doing probabilistic forecasts and so on.

So, to me, this is, you know, an alternative to taking our model estimation and putting it into something more generic, like SAS.

CHAIR WEISENMILLER: Right.

MR. KAVALEC: And what’s also appealing about this, as well, is the users’ group. A lot of people sort of doing the same thing or similar things, and you can learn a lot that way.

CHAIR WEISENMILLER: Yeah. No, I agree. I agree. I think, certainly, their expert panel started and one of the things we wanted to do was look at the different types of models, hybrid -- anyway, to start thinking a little bit more, I suppose, to just this -- this is the model we’ve had for 40 years and not going to have for the next 40.

Well, I mean, yeah, he’s going to have to do a lot with the ISO expansion on the change. I assume that’s the option that does the longer term for the other --

COMMISSIONER MC ALLISTER: I guess, I would just -- you know, and I know this is a work in progress. But the boundary, the boundary issues of what your analysis is going to cover and then what we do as a State agency, as the ISO expands, it seems like that’s worth a quite a bit of thought. You know, you don’t want to be redundant but also, we want to make sure that the California analysis is an appropriate California analysis. So, you know, we already have some of those issues and just the not complete membership in the ISO that we have to deal with. You know, so we have non-ISO members, but that's -- and then we're going to have ISO members that are impacting you, but not us, or at least our forecast for example. So, anyway, I'm sure you're thinking about that. But that seems like that might be a challenge going forward.

MR. EMMERT: Yeah, we actually are working through some of those issues as we look at expanding the RA program into more of a regional RA outside of California, and how do we coordinate between the forecasts that we would assume currently would still come from the CEC, and roll those into a forecast process where we combine forecasts in the larger footprint.

COMMISSIONER MC ALLISTER: Yeah.

MR. EMMERT: All right, thank you.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Thank you.

Next is Ken Schiermeyer from the San Diego Gas & Electric.

MR. SCHIERMEYER: I'm Ken Schiermeyer from San Diego Gas & Electric. I'd like to thank the Commission for having me speak on this topic. It is actually one of my favorite topics, too.

So, I enjoyed the presentations on this, too.

Very enlightening and I would like to see a working group for this, too.

You know, I'm going to present what we're doing. But our -- you know, our journey through this isn't complete. It's what we could do now and we have future considerations that we'd like to incorporate, too.

Our hourly forecasting process was actually born from short-term models. So, I'll go into that a little bit later. But, you know, like what Chris is trying to do, we're trying to reconstitute what we think consumption is and forecast that. And then, include hourly load modifiers to get a look at what impacts those have on future load shapes.

Currently, the modifiers include solar and electric vehicles, and energy efficiency in the later years, especially. I know the CEC has made available, you know, some of those AAEE hourly load shapes. And we'd like to be a part of that conversation in the future, too.

And then, future considerations will be the impacts of battery storage. That's what that happy face thing is. Other people got confused that that was an appliance, but I guess it could be both, you know. And then, the impact of time of use rates in the future.

We forecast hourly loads by rate class and we do so as the way -- for the reasons that Chris described before. If you have one class that is growing at a faster rate than another, you want to incorporate that impact into future loads. We split it up between residential, small commercial, medium, large commercial, agriculture and lighting.

We're using historical Smart Meter data. Right now we have 2013 through '15 and that's because of the availability of Smart Meter data. We'd certainly like to use more, you know, as time goes along.

We incorporate weather data. Ours is currently in a daily format. And a lot of calendar information. And then, anything else for other that you think will impact hourly loads in the future.

Alan, I especially liked your presentation. And we currently don't include impacts like that, but I see that being, you know, what we'll do in the future.

These hourly models are -- they're hourly, so there's 24 for each day, you know, for each rate class. And we combine them to create a forecasted load shape.

For controlling electric vehicles and rooftop solar, like I said, we add it back to the net load to come up with a consumption level load. Except for electric vehicles, we take them out because they have such a different load shape than the typical system load shape.

And we forecast hourly consumption and then we adjust those hourly consumption estimates by subtracting out PV and adding back the EV.

Here’s an example of forecasted 2016 nonresidential loads. So, you can see, you know, the patterns. It’s hourly level data. And it’s hard to see because you have 8760. But you can kind of see kind of the seasonal patterns, at least.

And then the residential sector, you see -- we designed this on normal load or normal weather. And that’s kind of a lengthy process and maybe for a workshop. But, typically, San Diego sees mild weather most of the year, and then we have these heat storms, a couple of them every year.

Going down into an example, and this goes -- this kind of incorporates some of the previous presentations that we saw today regarding peak shifts. And on the left you see our solar generation estimate and below that you’ll see the electric vehicle load.

And in the final load, what our model, at least on a consumption basis is estimating, is the blue plus the yellow. And to come up with net system load, we subtract off the yellow and add in the red, which is electric vehicle load.

And in this example, you can see, you know, the peak being close to noon, you know, prior to solar, and then being pushed out into the evening hours.

Here’s a system peak day. This one, you know, it does shift a little bit but not as much, I think because of the air conditioning load, it’s so large in the middle of the day. But from what I’ve finding, you know, the needs of this hourly data, it’s not so much the peak day, only, that people are interested in, they’re interested in all the other days, too. You know, about when customers are using energy, on an hourly basis.

You know, again, future considerations, you know, the battery storage and the time of use impacts. And then, you know, also incorporating, for the longer-term forecasts, a lot of these end use indices that will affect consumption loads in the future.

But with this -- you know, with this kind of platform, we feel like it gives us a flexible tool to handle or evaluate impacts on system peak in the future.

That’s all I have.

COMMISSIONER MC ALLISTER: So, just a question on the EV loads. As they -- you know, we’ve got a big goal, expecting the EVs to go up, going forward, quite a bit. And I noticed on that bottom graph, you know, you've got quite a bit of sort of on-peak charging right there. I mean, it's nothing like the nighttime, which is great.

MR. SCHIERMEYER: Yeah.

COMMISSIONER MC ALLISTER: I mean, you know, sort of pushing it to the nighttime is sort of the traditional management. But I guess now, that we're going to have all this energy in the middle of the day, I wonder if SDG&E's going to try to give folks an incentive to really charge in the middle of the day?

MR. SCHIERMEYER: Yeah, to develop this load shape, we used the -- there was an EV study from EcoTality a few years back. And we combined load shapes based on different control groups. We noticed that -- we had an estimate of how many electric vehicles were in our service territory, but only I'd say roughly half were on TOU rates. And so, they had no incentive to charge off-peak.

But I think over time, you know, as customers try to reduce their bills, more and more of them will move to TOU rates and charge off-peak.

So, in the '16 forecast you see more there. But if we were to do a 2026 forecast, you'd see less.

COMMISSIONER MC ALLISTER: Yeah, good. Great, thanks.

MR. SCHIERMEYER: Uh-hum.

CHAIR WEISENMILLER: And, obviously, you have a relatively small service area, you have lots of solar, you have lots of EV, in a way, although I think it may be more EV percentage wise, obviously. But just trying to figure out how do you deal with, you know, say Borrego Springs versus downtown? I mean, how much do you differentiate, if at all, across the different areas?

MR. SCHIERMEYER: Yeah, in this analysis we don't quite separate out by areas at this point. But, yeah, I do see, you know, Borrego, a very small community, with a lot of things going on there versus a very highly populated like downtown. That might be a future consideration to, you know, break these down into even finer levels.

Right now, we're forecasting residential at a system level but, you know, given the availability of Smart Meter data you might -- you might be able to go down to different segments. At least coastal, inland, you know.

CHAIR WEISENMILLER: Yeah, and thanks for being here. And would certainly encourage you, and others, to continue the dialogue on these issues.

MR. SCHIERMEYER: For sure, yeah. Thank you.

COMMISSIONER MC ALLISTER: Thanks.

MS. RAITT: Thank you.

So, next, we have an opportunity for comments from the audience, if anyone had comments.

Okay, then we'll move on to Chris Kavalec, again, speaking on Geographic Disaggregation.

MR. KAVALEC: Okay, this is really just sort of a status update and it will be real quick because we're just kind of starting this process.

We've had some discussions, recently, with PG&E and Edison about sort of optimizing the geography at which we forecast, to make our forecast as useful as possible for their transmission planning. So, that's what this is about.

And first, just a review of what our current geography looks like. We have eight planning areas that are based on Balancing Authority areas and transmission and access charge areas. And within those eight planning areas we have 20 forecast zones, most of which are in CAISO, obviously, because CAISO's most of the State. And the ones that -- and these approximate what CAISO calls their transmission zones.

But they're based on county borders, due to the constraints we have in terms of projecting economic and demographic variables. So, this is always an issue, you know, political boundaries that constrain our forecast versus the physical infrastructure.

So, the planning areas, PG&E has most of the north, Southern California Edison is most of the south. And we have San Diego and Imperial in the far south, a couple of planning areas within L.A. County. And then we have what we call Northern California non-CAISO, which is just what it sounds like. Those not within the CAISO territory, but in Northern California.

And here are the 20 forecast zones. We have six within PG&E, five within Southern California Edison. LADWP has a couple of forecast zones, and Northern California non-CAISO has another three forecast zones.

So, this is where we are now in terms of our geography. And currently, the IOUs use the IEPR forecast as a benchmark for their transmission planning, as they go from the bottom up, at the TAC or service territory level.

So, our goal is to develop a more disaggregate, optimal geography IEPR forecast to better serve their transmission planning. So, that would mean that their top down -- or their bottoms up utility results would be benchmarked to a higher granularity geographically than the total service territory level.

So, we’ve been talking to PG&E, and Southern

California Edison, and we will soon be talking to San Diego.

So, for Southern California Edison, they have suggested that the IEPR forecast go down to the A-Bank substation level or some aggregations of the A-Bank.

The A-Bank is the step down from the transmission to the sub-transmission level. And then they go to the B Bank, which is a further step down to the distribution level.

But anyway, there are 50 of these A-Bank substations. So, our next step is to sit down with the Edison transmission planners and investigate, figure out the feasibility of mapping our IEPR forecast into a geography that approximates the A-Banks or groups of A-Banks.

Now, PG&E, on the other hand, is much less centralized. They don’t have anything comparable to the A-Banks. It’s just the way that the system was built a long time ago. So, our task here is to develop a grouping of around, within 1,400 distribution substations into a manageable number of sub-areas.

And so, we’ve had discussions in the last month with PG&E, and talked about everything from the sub-lap level, all the way up to the transmission division.

And our next step, we agreed on with PG&E, is to do a GIS comparison and see how closely our forecast zones can be mapped or sections of our forecast zones can be mapped to transmission divisions.

And so, that's where we are now. And so, we'll keep you apprised of these discussions as they happen, and I'll let -- after the Commissioners, any Commissioner questions or comments, I'll let Edison and PG&E comment on this, if they want to.

CHAIR WEISENMILLER: No, that's good. I would obviously want to get the ISO's opinion and encourage you to connect with at least LADWP and SMUD on similar questions.

MR. KAVALEC: Okay.

CHAIR WEISENMILLER: And at least then, obviously, we have the whole IRP crowd, and then may or may not get into the specific question.

COMMISSIONER MC ALLISTER: Yeah, I guess is this sort of a fingers-crossed they match up well and, you know, you get some group of sub-laps that do correspond? And if you don't, I guess is what's the plan B?

MR. KAVALEC: There is no plan B.

COMMISSIONER MC ALLISTER: Okay.

MR. KAVALEC: Yet. But a quick look, at least on the PG&E side, many of their transmission divisions correspond to county borders, which is very helpful for us, in our forecasting.

COMMISSIONER MC ALLISTER: Okay. Well, that’s good. So, I have my fingers crossed. Okay, great. Thanks.

MR. KAVALEC: Okay.

COMMISSIONER MC ALLISTER: Was that a call for Edison or PG&E to make a comment or --

MR. KAVALEC: That’s right.

COMMISSIONER MC ALLISTER: -- if they want?

MS. RANDOLPH: I don’t see anybody jumping to the podium.

So, that would take us to the public comment period. I didn’t receive any blue cards. But if you can raise your hand or step up to the podium, if you have any comments.

KHALA: Hello, my name is Khala and I work with NRDC. WE would like to thank the Commission and staff for all their important work to improve data and analytic techniques in the demand forecast. And also, for increasing coordination between the ISO, CPUC, and CEC.

These 8760 load profiles of AAEE and other distributed energy resources are a huge step forward, already opening this conversation on when the peak hour and ramp-up hours will be in the future.

NRDC wants to make sure the hourly AAEE forecast is an accurate representation of energy efficiency throughout the day. Right now, we see that the AAEE forecast load shape mirrors the overall load shape. And we hope staff will look into this more in the future and make sure that this is an accurate representation.

NRDC is very encouraged by all the progress on the demand forecast and we look forward to working with the CEC to make sure we plan for the targets set by SB 350. Thank you.

CHAIR WEISENMILLER: Okay, thanks for being here. We certainly than NRDC for their help in this activity.

COMMISSIONER MC ALLISTER: Is that it? Nobody else?

MS. RAITT: Anybody else? We don't have anybody on WebEx. I may have phone lines to open up.

And we don't have any phone lines, so I think we're done with public comment.

COMMISSIONER MC ALLISTER: Okay. Well, great. I guess I just want to make a couple comments. So, this is, again, we talked a little bit about what's upcoming in future workshops. But, you know, absolutely we could definitely dig in on the demand side stuff, the whole energy efficiency, obviously, front and center. We have a big goal in SB 350 to double it. Well, you know, goal setting, what does that actually mean? And I think it's pretty clear, just to build on that comment from NRDC, you know, we need to target energy efficiency in a way that's relevant for this discussion, and we need to have the tools to quantify how that's working. You know, where is the energy turning up geographically and temporally.

So we do, you know, absolutely have to build analytical tools and data flows that enable us to get a handle on that, and really track it going forward. Because the last thing we want is to have this sort of, okay, here's what we think's going to happen in the future, but then get to the future and not be able to look back and understand what happened.

So, we really need it for both the forecast and the retrospective look.

It's important for policy development at all levels, including programs for energy efficiency, and as well as the forecast. So, this analytical task that we're embarking upon has all sorts of benefits, if it's done correctly. And so, you know, if it's done correctly, so we really need to focus on this, this year.

Demand response is the same sort of thing.

We've got a program at the ISO, we've got a program at the PUC, with the investor owned utilities at the retail level, and both of those are sort of nascent. So, we've got to build in the understanding, you know, capture the understanding from those efforts to target our programs, and policies and, really, our funding decisions and what we ask the Legislature to support and what we propose to the Governor. You know, that how are we going to move forward in a way that really gets this done, working with the marketplace.

So, for all these reasons, this work that we've talked about today is really, really important and I would encourage everybody, who's interested in this, to keep participating. I believe it's the 11th and then the 27th we have workshops that are related to the -- particularly the forecasting methodology and, in particular, related to energy efficiency. Obviously, of interest to me.

And it's a great opportunity, really, to move into the 21st Century, to put together the duals that we need both to plan and to evaluate. And I think, increasingly, the various types of resources will require similar tools. So, demand response, efficiency, whether it's supply, whether it's storage, whatever. All of those will have attributes that we need to understand and that will have to complement each other as we plan.

So, I think there is a lot of urgency to get to this discussion and, you know, we're going to have to put some resources in this and build the tools that we need.

So, I want to thank Chris and staff for drawing this discussion in the forecasting context.

CHAIR WEISENMILLER: Yeah. No, I certainly want to thank people for their contribution today and encourage the dialogue to go along.

And I think, I tried to indicate this morning is, obviously, there are some degree of silos, or boxes, although we're connecting across those. So, in the IEPR, we're looking at forecasting issues.

At the same time, there's two other proceedings or dockets that I encourage folks to take sort of a holistic look across them. And one of them is 802 and the other one is the IRP.

And so, as we go forward, basically, some of events will pop up in one of these three venues. Certainly, the two of us are trying to integrate over the top of those. And again, this is the mechanics of forecasting. Certainly, the meeting of the doubling goal is -- you know, it's hard at times to draw the lines between what's in this, what's in 802, versus what's in the IRP. But we're trying to take, anyway, a somewhat coherent approach.

We're also, in the 802, is going to drive a lot of the data questions.

But as Commissioner McAllister indicated, for the doubling issue, the first question is going to be what is the baseline, and that's sort of an upcoming IEPR workshop. And then, there's the goal-setting activity going forward.

While President Picker and I are having more, you know, looking at the doubling in the context of the forecast workshop. So, anyways, it's going to be a busy year, decade, to try to sort through all this.

And so, anyway, we look forward to your help. Certainly, written comments are due. And, you know, particularly look at the various dockets. So, there are parts of this that are more interesting -- anyway, just trying to avoid someone saying I was really interested in X, but you didn't tell me that it was in this other docket. But, so to keep your eye on this, IRP and 802, right.

So, thanks again.

(Thereupon, the Workshop was adjourned at 3:25 p.m.)

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Kent J. Odell

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