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CALIFORNIA ENERGY COMMISSION

STAFF WORKSHOP

In the Matter of:	) Docket No. 19-IEPR-03
	)
	)
	) STAFF WORKSHOP RE:
	) Data Inputs and
IEPR Lead Commissioner Workshop	) Assumptions for 2019
	) IEPR Modeling and
	Forecasting Activities

CALIFORNIA ENERGY COMMISSION (CEC)
IEPR LEAD COMMISSIONER WORKSHOP

CALIFORNIA ENERGY COMMISSION

THE WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MARCH 4, 2019

10:00 A.M.

Reported by: Gigi Lastra

APPEARANCES

COMMISSIONERS (AND THEIR ADVISORS) PRESENT:

Janae A. Scott, Vice Chair
J. Andrew McAllister, Commissioner
Karen Douglas, Commissioner
Ken Rider, Advisor to Chair David Hochschild

IEPR Program Manager:

Heather Raitt, California Energy Commission

CEC STAFF PRESENT:

Cary Garcia
Nancy Tran
Richard Jensen
Angela Tanghetti
Anthony Dixon
Lynn Marshall
Sudhakar Konala
Ysbrand van der Werf
Mark Palmere
Chris Kavalec
Nick Fugate

PRESENTER

K.G. Duleep, H-D Systems

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P R O C E E D I N G S

MARCH 4, 2019 10:02 A.M.

MS. RAITT: Good morning. Welcome to today's IEPR Commissioner Workshop, the 2019 IEPR Workshop on Data Inputs and Assumptions for the 2019 Forecast.

I'm Heather Raitt, I'm the program manager for the IEPR. I'll quickly go over our housekeeping items. If there's an emergency, we need to exit the building, please follow staff at the door and across the street to Roosevelt Park.

Please note that our workshop is being broadcast over WebEx, our conferencing system, and so it is being recorded. We will post an audio recording on the Energy Commission's website in about a week -- a week. And a written transcript in about a month.

We'll have an opportunity for public comments at the end of the day so you can fill out a blue card and give it to me. And we will do that at the end of the day. There'll be opportunity for three minutes of comments per person and you can give comments at the center microphone. And for folks on WebEx, just please use your raise your hand feature to let us know that you'd like to make a comment and we'll open up your line at the appropriate time.

Materials to the meeting are at the entrance of the hearing room and also posted on our website. And written comments are due on March 18th and the notice has all the information for providing comments.

So with that, I'll turn it over to the commissioners. Thank you.

VICE CHAIR SCOTT: Well, good morning, everyone.

Thank you for being here with us today as we go through our data inputs and assumptions for the 2019 IEPR modeling and forecasting activities. As you know, it's pretty data driven and very wonky but it's incredibly important to make sure we've got good data and information as we run the models for -- for our forecast.

So we have actually a pretty busy day. So I'm going to just turn it to my fellow commissioners to see if they'd like to say good morning and we'll go from there.

COMMISSIONER MCALLISTER: Sure. Yeah, thanks everybody for coming. I want to -- so this is a core activity of the Energy Commission. As you all know, we've been doing this for 40 years plus and it's one of the reason the commission -- one of the reasons the commission was formed and stood up in the first place.

And, you know, we're in a -- we're in a new era, we're in the digital age, we're in a data heavy environment. And so in the con -- as we sort of try to metamorphous I'd say the forecast and update the methodology of the forecast within that, so this is sort of this year's forecast as one step in the direction that we need to go, to more granular, more temporal, sort of more heavy data intensive forecasting efforts, that's the longer term context. So for this year, we're having a conversation for this forecast but if you sort of look at it in several cycles down the road, we're going to keep improving each cycle, the methodology, so that we end up in a place that we can really do justice to SB 350 and SB 100 and all of the policy drivers, all the legislature drivers that we have going forward to 2030 and beyond. So that's the sort of broader context.

Anyway, I will leave it at that and see if Commissioner Douglas has anything to add.

COMMISSIONER DOUGLAS: No. I'd just like to welcome everyone here for this workshop.

MS. RAITT: All right. Great.

So the first presentation is from Cary Garcia, staff from the Energy Commission to provide an overview.

MR. GARCIA: All right. Good morning. So I'm Cary Garcia, the lead forecaster for the Demand Analysis Office. I will ease into the wonkiness today but we're definitely going to get deeper into that as we get in so I'm just going to give a high-level overview.

And as we know, 2019 is going to be a full forecast -- or full IEPR. So this is where if you remember last year's update, we kind of kept it sort of in-house to the Demand Analysis Office running some econometric models to update our previous forecast from 2017. But this year we go and coordinate with our Supply Analysis Office, our sister office, and they'll run a little bit more analysis.

So getting into here, like as I mentioned, it's a full forecast. Right now we're receiving input demand data from the IOUs and other LSEs in the state. And the final date for that -- or one of the final dates is April 2019.

We're hoping to have a preliminary workshop to present the results of the preliminary forecast in August of this year, aiming for a December workshop for the revised forecast. And then we'll do a revised workshop adoption of that forecast in January of 2020.

Just sort of walk you through the process a little bit. I'm going to walk you through the process and then we'll get into some of the common case assumptions that we talked about. So really it starts with our previous forecast. This is our first iteration, there will be an iterative process that I'll explain a little bit later. And that information is going to go into an electricity dispatch model or production cost model. And from that, you get a sense of what the energy demand is -- or sorry, the natural gas demand for generation will be in the WECC footprint. So not just California but the larger western part of the United States.

And that information is then fed into natural gas -- I'd have to look to Anthony again for the full name but essentially it's a natural gas market demand model for North America. And so once you get that information into there, then you're going to get information related to the electricity price -- or sorry, the gas prices for wholesale natural gas. And you're also getting the small amount of natural gas that comes from our transportation model that was developed last year for natural gas vehicles. It's going to feed into there as well.

There will also be like an iterative process that may occur. In some cases you may see some peculiar results in a production cost model or some peculiar results in the natural gas demand model, and so it'll be some iteration potentially. But ultimately you end up with those prices for natural gas that feed into our electricity rate forecast. And that -- those prices will also feed into the transportation demand forecast models as well as our energy demand models both for electricity and natural gas demand.

Additionally, the NAMGas is also going to provide -- as I mentioned for the natural gas components -- prices as well for the transportation as well as end use for energy demand models for the preliminary 2019 forecast. Ultimately, transportation is also going to feed into the natural -- our energy demand models, and then we'll run a second iteration of that with a preliminary forecast and we go through this all again and you end up with the revised forecast that I mentioned we would have completed by December 2019.

I'll stop there, if there's any questions. I should mention that folks are going to get into more detail on production cost, NAMGas, rates, and transportation.

All good from the dais? Okay. I see a lot of nods.

So once again, this is just kind of reiterating what I just said here. That first iteration using the forecast update as the primary input, the result of that is our preliminary energy demand forecast. The second iteration, we used that preliminary demand forecast and the output will end up being the revised 2019 forecast.

And so as we're doing this process, we really want to develop some common cases. You see there's many different models and so we kind of want to be on the same page there. And so the goal of developing the common cases is really to simplify the transfer of data between models and maintain a consistent analytical basis for our policy discussions and questions. So you really just want to make sure on the same page. So it's not really like an integrated modeling approach because we have several different models, but it's a coordinated modeling approach so we're doing communication and we're comparing the same information and data across different models.

Some of the basic assumptions that I have here. So we have GDP, gross state product, population of households, output information by the NAICS categories that we use. Carbon prices, assumptions that are used in electricity rate forecast, weather, like cooling degree days, heating degree days. And then as you'll see today, there's some specific assumptions for each of the models that we'll be presenting.

And the three common cases, essentially just break down into a mid, high, and low cases, so they're really, I should say they're energy demand cases. And so the mid case is really just our reasonable expectation, just that most likely outcome and that's given baseline assumptions that we'll talk about a little bit today.

And our high and low cases I should mention are not really extreme cases but they're sort of the way I view them is as are reasonably expected bookends, they create a nice spread, that nice balance of uncertainty that goes out into the future. And I should also mention, I have a slide that kind of goes into this a little bit later, that our high and low demand cases, for example, aren't always would you say if you recall your supply and demand curves, one of the key assumptions that we make is that there's high electricity demand has lower rates. But if you remember that supply and demand curve, as you get more demand, the prices creep up a little bit. So we're not necessarily consistent on that end but what we're trying to do with these high and low cases is create that reasonable bounds. In the end, a scenario like that where you have higher prices and higher demand, it would fit within that bounds of uncertainty so we're still capturing that in our demand forecast. So we're kind of just tweaking things a little bit to capture all those expectations that could occur.

And as I mentioned here, here's a little quick overview of the baseline demand scenarios. So you see just some of the basic assumptions here, economic and demographic assumptions; rates; self-generation forecast, which we'll talk about later; electrification assumptions around like port electrification and trans electrification; and as well as climate change. And I'll talk about this -- I'll talk about climate change a little bit more later today.

So just kind of looking at our high energy -- well, let's actually start off on our mid-energy demand. So this is really just our likely scenario in here. So everything's about in that mid case or baseline scenario, econ, demo, rates, and such. And I should also mention that climate change. We do have a moderate amount of climate change occurring in our mid demand scenario.

But looking at the other bookend scenarios, the high-energy demand, for instance, will have obviously higher economic and demographic assumptions, lower rates that I mentioned to create that bounds which leads to lower self-generation impacts as well as but with higher electrification and then more climate change impacts to create that consistency. And on the flip side of that, just low-energy demand with sort of the bookend scenario, the kind of the opposite of those high ends, high-energy demand scenarios.

And so basically I think we need to flow into our econ and demographic scenarios, but I'll stop here if there's any questions at all.

Okay. All right. There you go.

So we're going to have Nancy Tran is going to talk about our economic and demographic assumptions.

MS. TRAN: Good morning, my name is Nancy Tran -- a little short -- from the Energy Assessments Division.

Today I'll be presenting California's economics and demographics. The purpose of this presentation will be to give an overview of economics and demographics. Give some background information that's considered in our demand forecast. Summarize some comments made from experts and the experts we use, our vendors, Moody's Analytics, Global Insight, Department of Finance, as well as some academic experts such as UCLA and their support cast. I'll also be describing some major uncertainties over the next ten years.

California's energy policy has made significant progress over the last few decades in reducing energy consumption through efficiency and other demand-related efforts. However, economic and demographic patterns remain the most significant factors in determining energy consumption. An example is this graph. Clearly it shows that the impact of the economy on electricity consumption by plotting statewide employment alongside consumption over the last couple decades. And this also shows the impact of recession on energy demand as you could see with the arrows indicated in 1990, 2002, and 2008. The effects of the last recession are particularly apparent as both employment and consumption take a large dip at the beginning of 2008.

This slide shows the severity of the last recession we had. As you can see in 2009, California dropped well over 5 percent. California's annual employment growth has returned to prerecession levels, growing at an annual rate of 3 percent. This also shows that after 2011, California is recovering faster than the rest of the nation during the Great Recession.

California is typically hit harder during recessions than the nation as a whole because California is very procyclical with high concentrations of tech companies and startups that rely on funding from the capital markets. We are due for another recession in the short term but there is a lot of uncertainty as we anticipate the next downturn but none of our experts are really trying to project this in their long-term forecast. So. But the economists are also stating that California won't be as -- the recession for California won't be as damaging as it was for the -- when we had the Great Recession.

So many drivers are used in the development of the demand forecast for economic sectors, residential, commercial, industrial are the main sectors along with PV, adoption, and transportation forecast. The presenters will provide more detail on PV and transportation forecast later during this workshop.

We continue to use Department of Finance for our population and household projections. For the 2019 preliminary forecast, the population data did not really change, so we'll be using the same ones from our 2018 forecast. The reason being is the July 1 estimates have not been released by Department of Finance. And we are hopeful in the future to work alongside Department of Finance for -- to have them develop more scenarios for population and household for us. And all of our other drivers that we use will be from Moody's Analytics.

So move on to California's demographics. This slide shows historical population in California. Population growth is slowing since that last 20, 30 years. For example, just in the last year, population growth was less than 1 percent versus 1.8 annual -- average annual growth from 1980 to 2000.

Although population trends are slowing, population is estimated to grow about 1 percent over the next 25 years, according to the Department of Finance. This graph also gives you an idea of our mid case that we'll be using for our 2019 forecast.

So now I'll go into two important aspects of population growth which is birthrates and migration. Our experts have stated these are the following drivers associated with population growth. Birthrates have been slow since the Great Recession and will continue to grow slow. About 471,000 California babies were born in 2017 which is down 3 percent from 2016, according to the CDC. Birthrates fell nationwide and worldwide, so this is a worldwide phenomenon.

Another important component of population is migration. According to the demographic experts, net migration will continue to be a positive due to international migration. However, international migration has slowed since the implementation of the administration's immigration policies. We'll keep track of this as we go on.

California's inland region population is expected to grow faster than the coastal regions. In fact, this has been occurring over the last few years. But the coastal regions still have a larger population. Overall, California continues to have low domestic migration due to the lack of housing and affordability issues.

So Moody's provides economic projections for our energy demand forecast. They have built a custom higher scenario for us to use. Previously we used other vendors, however it produced inconsistencies when moving across variables in the different demand scenarios. The custom scenario that they have built for us provides more consistency in the data across the scenarios which is also capturing a reasonable range of uncertainty.

This custom scenario will incorporate assumptions such as increases in military spending, successful trade talks, increases in nonresidential investment, a stronger labor market, stronger productivity, higher wage growth, and faster consumer spending growth. The baseline scenario has provided reasonable projections in the past so we'll be using that as our likely scenario for the 2019 forecast. For the low scenario, we had a few options, short term, slower near-term growth, moderate recession, and below-trend long-term growth.

So in this case, we want to make sure that we don't make any short-term assumptions about any recessions occurring but rather maintain the uncertainty in the long term. So in this case, S-5 would make the most sense in our forecast as we look at the variety of scenarios that we have from a variety of data vendors that we use.

So this will help you visually understand what we're looking at. The 2018 forecast is a stand-in for the expected high scenario that Moody's is currently developing for us. For forecasting purposes, we stayed away from timing the next recession. Therefore, we will show long-term growth here in the mid case keeping long-term trends as we develop the high and low scenarios. So now that we have determined the appropriate low case, we'll align all three demand cases with our economic and demographic scenarios.

The mid-term growth will come from a boost in tech and housing. Our experts expect gross date product to grow around 2 to 3 percent a year. As we enter into an economy with full employment and slower economic activity, come 2020, we'll be growing at about 1 percent a year.

Long-term growth is expected to keep pace with the rest of the nation because of our high-tech industry and investments in infrastructure. Overall, the next ten years we'll be seeing about 2 percent growth compared to 2½ percent growth 20 years ago.

Continuing with the comparison of our last forecast with the new current forecast with their mid cases, here's a chart with a few of our economic variables. You'll see gross date product is up .2 percent in 2030, personal income is down 1½, manufacturing output is down 2 percent, and nonfarm employment is up .18 percent in 2030.

A key driver is the growth of construction in California. Housing is still lagging in both single and multifamily units. Economists have stated this trend is going to continue because we have limited number of skilled construction workers as well as increases in material cost due to the tariffs. Single family housing will continue to grow a bit faster than multifamily units as household formation rates rise. Residential and nonresidential permits had a fairly large increase since the recovery. However, it is still very far from the number of homes we need built every year. We need about 180,000 units built every year in order to keep up with population growth.

Other short-term economic drivers include housing affordability which continues to be a huge factor hindering the economic growth throughout California as we are unable to afford -- as many people are unable to afford housing. Also the fires in 2017 and 2018 have a long road to recovery as they continue to rebuild in those local communities.

COMMISSIONER MCALLISTER: Hey, Nancy, can I ask a question?

MS. TRAN: Yes.

COMMISSIONER MCALLISTER: If you could go back to Slide 11, the little table.

MS. TRAN: Yeah.

COMMISSIONER MCALLISTER: Just to be clear -- yeah, right here.

MS. TRAN: Uh-huh.

COMMISSIONER MCALLISTER: So this is the difference with the last forecast, right?

MS. TRAN: Yes.

COMMISSIONER MCALLISTER: This is not any absolute numbers, but relative.

MS. TRAN: Yes.

COMMISSIONER MCALLISTER: Is that correct?

MS. TRAN: Correct.

COMMISSIONER MCALLISTER: Okay. Just wanted to make that clear.

And then, are we going to do -- on the housing, back to the housing starts.

MS. TRAN: Uh-huh.

COMMISSIONER MCALLISTER: Are we going to do -- are you going to do any scenarios around different pathways for housing starts in terms of, you know, obviously that's a big priority for the new governor, and --

MS. TRAN: Yeah.

COMMISSIONER MCALLISTER: -- you know, if we have some solution from the legislature to, you know, crank out more multifamily housing.

MS. TRAN: Uh-huh.

COMMISSIONER MCALLISTER: Any sort of scenarios like that in the works?

MS. TRAN: I believe it will be part of our residential model.

Correct me if I'm wrong, Cary or Nick, one of you.

MR. KAVALEC: Yeah, we put together a residential housing forecast that includes new starts. And that's typically based on the housing forecast that Moody's provides us. So we basically match new homes with the household -- overall household growth rate given expected decay from year to year.

If you have specific ideas about other things we can do to tweak the -- the housing starts, incorporating various, you know, expectations, we're -- we're happy to do that too.

COMMISSIONER MCALLISTER: Yeah. It's a conversation we probably ought to have. I mean, you know, I don't have a crystal ball and nobody else does either, right? But I think obviously that's a top, top priority in a way that it hasn't been in the past. So. Thank you.

MS. TRAN: So I think I was on the third bullet.

Income growth from tech has spilled over to other parts of California regions like Los Angeles to San Diego. With this comes more growth and entrepreneurship, emerging technologies and innovation, and innovation's one of the keys to growing gross -- GDP.

The federal government's stimulus money helped boost the economy in the short term but, you know, it has run out. So we're going to see what the federal government's going to do just to try to continue boosting the economy.

VICE CHAIR SCOTT: Hey, Nancy, just a quick question on that government stimulus.

MS. TRAN: Yeah.

VICE CHAIR SCOTT: Is that the -- the tax cut or you're thinking about --

MS. TRAN: Yes.

VICE CHAIR SCOTT: Okay.

MS. TRAN: Yes, the tax cuts.

So now I'll summarize some of the four major regions of California.

Los Angeles region is among the largest and most diverse of the regions. The unemployment rate has decreased to less than 5 percent. However, the labor market is tightening throughout California. The expansion of technology firms including Biotech is occurring in Los Angeles generating competitions for firms in Silicon Valley and the Bay Area. Housing prices are still high due to the lack of supply and high demand.

Moving further down south to San Diego. The San Diego region's unemployment rate has decreased to 4 percent -- to less than 4 percent. There is expected job growth in Biotech, defense, and manufacturing. San Diego is one of California's most concentrated centers for clean tech employment with more than 2500 clean tech companies that have over 2000 jobs directly linked to the clean tech sector. With a much lower cost of living than the Bay Area, San Diego is definitely a competitor to keeping those companies growing within the region. Housing prices in San Diego are inflated by limited supply and high demand as well as it is with the rest of California's coastal communities.

Moving up north to the Central Valley region. The Central Valley region's unemployment rate is less than 6 percent. Sacramento region specifically continues to be a healthcare hub for job growth along with leisure and hospitality. With more -- with a more affordable economy than the Bay Area, the Central Valley continues to absorb more residents and businesses from the Bay Area as it continues to provide better opportunities for them such as being able to purchase a new home, pay cheaper rent, or even lower business costs.

Construction is growing but at a slower pace throughout the region from apartment buildings, single family units, to commercial spaces. However, again, construction workers are still in demand and that's limiting faster growth.

The Central Valley's Visalia County has ranked -- was ranked as California's most affordable housing markets looking at cities with populations of 60,000 people or greater. Clovis and Bakersfield are also on that list. And this is the most census survey.

Now we move on to the Bay Area region. The Bay Area region continues to grow with their well-educated and highly skilled workforce. The tech boom caused strong wage growth and the sector continues to be the main driver in this region's success. Tech firms have the ability to integrate their products into infrastructures of businesses in all industries. The strong office market creates a demand for office space. However, tech firms and non-tech firms continue to search for cheaper destinations either across the Bay or anywhere in the West Coast.

Housing shortages will lead to faster house appreciation and a need for construction growth. This will be difficult as there's limited land in the Bay Area region and regulations that will restrict residential and commercial construction.

So overall, our economic experts predict positive growth for California. However, there are economic uncertainties and these uncertainties can restrict further economic growth. And these are the uncertainties that we want to highlight. So first of all, you know, we've had some great snow pack and plenty of rain this last season. There are still some areas that still have water restrictions due to drought or drought planning. In 2017 and 2018 engulfed California with several wildfires that left damaging economic and demographic effects on those California regional economies. If gas and oil prices continue to be low, it will fuel the economy, but we just don't know when it's going to go up.

For the impacted baby boomers and millennials, the uncertainty here is that the number of baby boomers entering into retirement continues to grow. So we want to know what -- how the millennial generation is going to pick up that slack in terms of jobs, housing preferences, or creation of multigenerational or cohabitational households. Also there is going to be a demand for their healthcare facilities.

Weather migration patterns to inland regions will continue. The effects of the administration's tariffs impacting manufacturing at our California ports is important. The effects haven't shown yet -- haven't been shown yet but, you know, we're anticipating it.

Lastly, the impact of the next recession whenever that occurs both in the short term and the long term is also an uncertainty.

And are there any other questions? Okay, great. Thank you.

COMMISSIONER MCALLISTER: Okay. Thank you.

MS. RAITT: Thanks, Nancy.

So next we have Richard Jensen and Angela Tanghetti to talk about production cost modeling from the Energy Commission.

MR. JENSEN: Good morning, Commissioners. Good morning, everyone. I am Richard Jensen, Supply Analysis Office here with Angela Tanghetti from our office to talk about our inputs and assumptions and provide select results for our production cost model.

These are preliminary, you'll probably hear me say the word preliminary several times here in the next few minutes. These are preliminary results that we'll be showing at the end of this.

As I move forward to the topic slide, I'll say a bit about our production cost model which is PLEXOS by Energy Exemplar. It's been on the market for 20 years and we have licensed PLEXOS for about ten years now so it's a tool we're familiar with. If you found yourself at a dinner party with a bunch of production cost modelers, and I'm not sure that you would, you could ask them about PLEXOS, I'm sure most of them would be able to speak to it. It's widely used and some of the current and former users would include the California ISO, Southern California Edison, and SMUD, amongst others.

We do use it to model all years of the forecast period and all hours of every year. Are primary output that we use in our office is natural gas burned for electric generation on an annual basis by hub or location and we pass that to the NAMGas folks and then they use that to run their simulations.

Briefly on the topics, Cary went over the common case. Load forecast, we'll talk about where we get our information from that. Retirements and additions to the fleet and how we track those. Updated hydro generation numbers, natural gas. Price comparison, the prices that we're using for this round of simulations and then some select simulation results.

Please, if you have any questions at any time, feel free to interject.

Briefly on the common cases here. High-energy consumption will have the lowest price; low-energy consumption will have the highest price. And I think the takeaway here is that all cases in our simulations are meeting the 60 percent RPS by 2030. And we do that with about 70 percent of in-state resources and 30 percent from outside of California.

The demand forecast for California, we're using the 2018 IEPR update which was adopted recently. I won't speak too much to that, the experts are in the room. For the rest of WECC, we're using the 2028 common case or the submittals that are very similar to the EIA 714 data, they're currently running out with their forecast through 2028. We take that combined with a 2017 historical year and calculate a growth rate for the intervening years. We also use that growth rate to extrapolate for 2029 and 2030 applied to 2028 loads.

Going forward for the revised simulations, we'll be looking at the actual annual data submitted to WECC and EIA 714. But in the interest of time, we did calculate a growth rate and took that route. It was also a little bit easier to generate the out of state RPS numbers that way.

For the preliminary and the revised simulations, we are using the hourly demand forecast numbers provided by the Demand Office. For areas outside of the ISO and outside of California, we have a tool affectionately known as Mr. Load Shape that takes five years of historical data and creates a synthetic shape. We use that and those annual energy numbers I spoke about to create hourly loads for all years of the forecast period.

COMMISSIONER MCALLISTER: So that's the first I've heard of this, Mr. Load Shape, I guess. Where did that come from?

MR. JENSEN: That might even predate me going back to Angela and Joel Kline from the electricity office many years ago. But we've recently updated that and they've tried to rename it to Dr. Load Shape, but Angela resisted that. So it's still known as Mr. Load Shape, for the record.

Again, I won't speak much about California, but here's the rest of the WECC. Just a comparison here for the 2017 IEPR low date for 2028 to the 2020 -- or to the 2019 IEPR. These are mid case by region. And you'll notice that most areas in this according to the bar chart are showing a decrease between the last IEPR simulations and the current round. And again, this is for 2028.

A bit on the fleet retirements and additions and some sources. We are using the IRPs as they come in. A few of them have come in and we've already gleaned information from that. But in addition to those going forward and the supply forms as well, we look at the OTC compliance schedule, we do out here the California once-through cooling plants to that. The ISO has an excellent retired to mothball list that's updated every several weeks.

We have a subscription database from ABB that we've licensed for several years. We monitor the Trade Press, Angela is active with WECC Anchor Data Set task force so some of the folks who are working in that group out of Salt Lake City do provide information on their fleet as well.

And in lieu of any concrete information, there's the 40-year rule, once a power plant reaches its 40^{th} birthday, we do retire that plant unless we have information to the contrary to keep it going.

A bit of detail on retirements and what we have for the forecast period. California natural gas retiring at larger numbers in the early years, this would be a lot of those once-through cooling plants. As we move through the forecast in the low hundreds of megawatts of capacity retiring, then after 2030 a little larger number. We see Diablo Canyon coming out of December of ’24 and August of ’25. Small coal plant retiring, I believe that might be Argus. And I did include WECC coal retirements here because the number is so significant and this might play a role in some of the preliminary, a slide I will show in a bit about natural gas burning for rest of WECC. But a large number, 17,000 or so megawatts of coal retiring WECC wide.

VICE CHAIR SCOTT: Do you have a sense of that 17,000 megawatts that you just mentioned, how much of the generation mix that is in WECC?

MR. JENSEN: Off the top of my head, I do not. It’s a large coal -- I will say regionally it does have some impact because you’ll see a large coal plant in Centralia in Washington, Boardman in Oregon, those are very large facilities in those states. But when you start getting into the Southwest and the Rocky Mountain states and the plains, there’s quite a bit of capacity.

VICE CHAIR SCOTT: Yeah.

MR. JENSEN: I don’t know that. But I can find that out for you.

VICE CHARI SCOTT: Sure. Please.

MR. JENSEN: Additions to the fleet. A similar list here. Again, IRPs will be helpful in the supply forms going forward. Siting Division, I have been in contact with them about two large thermal facilities that are currently under construction. The ABB subscription database, the Trade Press, WECC Anchor Data Set. Generic thermal additions for planning reserve margins. We don't want to leave anybody too short to where we would see unserved energy in the model or any price spikes that would alarm us. So we're careful about this but, you know, the rule of thumb has been 15 percent on a planning reserve margin. Considering all resources and their NQC values, generic renewable additions are added throughout California and the rest of the states to meet their RPS requirements.

A bit about those RPS additions, 2019 numbers are firmed up, that's pretty much installed capacity for in-state. This is looking at California here. For the mid demand, we're looking at again 70 percent or all cases about 70 percent in-state, 30 percent out of state. Capacity additions fairly modest for Biomass and Geothermal. Solar increasing about 9,000 gigawatts, some wind coming on as well. Well, in our model. So about 12,000 gigawatts. And that's a lot, but then again when you look at the 2030 RPS requirement of about 144,000 gigawatt hours, that's a large number. So we're building out to meet that.

A little bit on hydro here. We use the most 15 recent years of data that we have. Q4 for in-state, EIA data for out of state. This is in-state monthly generation from all hydro facilities aggregated. You'll notice that 2019 IEPR number a little higher than 2017 number so we had a couple of good years coming in, a couple of not so good years fall off.

One thing to note here is that -- oh, and for prospectively, the red line is the 2017 actual data and the 2015 as well. I threw those in because 2017 was such a good year for hydro gen and 2015 was not a good year, as you recall the drought. But the simulation, the monthly numbers do track well with the -- with the high case. We are seeing as well, a little bit of separation in the early months there, the February, March, and April numbers where we're seeing a little hydro generation this time around as compared to the 2017 IEPR. And about a 5 percent increase overall in that number annually. And these hydro generation totals are used for all cases.

Similar look here for rest of WECC. This is net of California. About a 1½ percent increase compared to the 2017 IEPR.

COMMISSIONER MCALLISTER: So just to be clear, those hydro numbers, those sort of middle of the road hydro numbers are used for all the cases, meaning that you don't do scenarios around what ifs, in terms of hydro good years and bad years?

MR. JENSEN: Not at this time in these cases, no, we do not.

COMMISSIONER MCALLISTER: Okay. Okay.

MR. JENSEN: Last time around we were mired in drought so we adjusted the front year number of 2017 to reflect hydro conditions that we anticipated to be below average.

COMMISSIONER MCALLISTER: Okay.

MR. JENSEN: Other than that, we use the annual number --

COMMISSIONER MCALLISTER: Okay.

MR. JENSEN: -- for August.

These are gas prices that we are using in the preliminary simulations. Now these were provided to us by the gas units in I believe July of 2018. I just pulled out some different regions here, couple of California, and the high, the mid, and the low for select years and near term and midterm in the outer year. Do want you to take note that in the high case, those prices are pretty low as we hit 2030. And in the low case, those numbers are substantially higher than the mid case. And we think that's going to show up in our slide I'll be showing you here in just a moment.

I'm going to advance ahead just to take a look at the WECC to Slide 15 here and then I'll come back to 14. So Rest-of-WECC natural gas burned for electric generation, pretty straightforward here. The mid lies below the high and above the low. Upward trajectory, again, I'll mention those retirements of the coal fleet that we did see substantial retirements as well as in this round we're seeing modest growth across the years in the out of state numbers for low.

I'll back up now to Slide 14. California natural gas burn for electric generation. So in the early years here we see the mid below the high and above the low, then we see '24 to '25 the upward tick there and that of course is in relation to the Diablo Canyon retirement I mentioned earlier.

A little bit of crossover in convergence in the outer year. So we still have some work to do on our resource build, the RPS resource builds, particularly out of state. We're also seeing those numbers, those prices that I mentioned earlier, the high demand case. Very low numbers and excess gas fire capacity in the Southwest leading to exports to California. So pressing our natural gas burn for electric generation to a point where the high case is below the low case. Counterintuitive, yes, but we think we've got a handle on that. We'll be looking at our wheeling rates and some other things and of course we'll be getting fresh gas prices that might change the look of this a bit as well.

One thing to note, though, we do see a downward trajectory in all cases. The low is a bit flat and then the convergence there at the end. We do have some minimum generation requirements on to keep certain amounts of natural gas on in various areas of the state and we'll be taking a look at that, too, and seeing what other entities like the ISO are doing to model that.

I believe that was the end of my slides. If there's no further questions for me, I'll pass it along to Angela Tanghetti. Thank you.

MS. TANGHETTI: Good morning. I'm Angela Tanghetti, and I'm -- I'm excited to share some of these interesting greenhouse gas emission results with our stakeholders and commissioners this morning.

In a few slides, I'll have a graphic and then I'll take that opportunity to explain why we are presenting electric sector greenhouse gas emissions and what staff plans to do with those. But as Richard has already described, we use the PLEXOS Production Cost Model to project various metrics for the IEPR common cases through the year 2030.

Two key simulation metrics for projecting greenhouse gas emissions are hourly fuel use for in-state resources, and hourly imported energy to meet California loads.

So for in-state generation, the GHG calculation is clear, it's Btu's of fuel use within the state boundaries, is easily converted to CO_2 because when a fuel is burned, the amount of CO_2 produced is strictly a function of the carbon content of the fuel burned.

The simulation from metric for imports to California is in terms of megawatt hours and energy -- and this energy is not quite as easy to convert to CO_2 since the fuel type of this imported energy is considered generic or unspecified.

So the technique we use to assign CO_2 emissions to imported energy is to first account for what we do know. We do know about long-term ownership shares of out-of-state resources for coal, for hydro, for nuclear, for gas, and for renewable energy. We allocate to the existing transmission system on an hourly basis, that is carving out a portion of each of these ownership shares and assign the appropriate CO_2 factor for each type of energy.

Next, we know the projected about of energy coming to California from the Northwest Region and also from the Southwest Region.

For the Southwest Region, the remaining transmission capability that is not allocated to these known ownership shares is assigned CO_2 emissions using the ARB Default Emission Factor which is .428 metric tons per every megawatt hour that we import.

Next, what we do know about the northwest imports is what we've learned from the ARB, the mandatory reporting data. What we observed from the past few years of MRR data -- well, it's many years, is that energy sales to California over the northwest inner ties are coming in as specified hydro energy. So approximately 80 percent, irrelevant of the year, of the reported energy sold from Power X and BPA is specified hydro, while the remaining 20 percent of MRR reported energy from the Northwest Region comes over as unspecified energy. Therefore, all the imports from the Northwest Region are assigned emission factor equal to about 20 percent of the ARB default emission factor.

Now for the RPS imports from both the Southwest and the Northwest Regions, we assume that up to 20 percent of these imports to meet the RP -- the California RPS come from something called Portfolio Content Category 2 and 3 type contracts.

Based on our understanding with the Renewables Office help of the AB-1110 legislation, those RPS resources in PCC 2 and 3 are not assumed to be GHG free. Therefore, all RPS imports from the Northwest and Southwest Region are also assigned 20 percent of the ARB default emission factor.

So finally, based on all those words, here's what the numbers look like as far as how we allocate emission intensity to imports from various regions and from what we know into California. Just note that on the -- near the bottom of the slide, the specified coal imports have twice the emission factor of unspecified imports. So it's just a -- kind of all those words in graphics just to show how we take the energy that we get out of our simulation tool and assign GHG emissions to that energy.

So this chart shows the 2019 IEPR common case projected GHG emissions for California. So in contract to what Richard shared on natural gas for electric generation in California, GHG emissions do fall into the expected high, mid, and low areas. That is the low demand cases below the mid and the high. Well, the high demand case is higher than the mid and the low.

This chart demonstrates that not only the in-state emissions and generation is key to the GHG calculation, but imports are as well. Careful consideration needs to be made about greenhouse gas emissions of projected energy imports. Any assumptions in this area can make a difference in the statewide calculation of electric sector GHG emissions.

This leads me to why we're presenting these results and how these results may be used in the context of this EIPR. Why? It's -- we're trying to begin a dialog with our stakeholders on methods and assumptions used to calculate GHG emissions using these electric sector simulation models. We've had to observe slightly different methods for import emission accounting. Also to demonstrate that simply because natural gas used for electric generation in California is declining and projected to converge to that minimum level by 2030, GHG emissions do not follow that pattern since California is dependent on imported energy from our neighbors.

How these results may be used? Well, during the 2018 IEPR update, our office provided the Efficiency Division and the Building Decarbonization Teams GHG projections to quantify savings from various types of energy efficiency programs. Also in the building decarbonization context of fuel substitution potential GHG implication associated with fuel substitutions in buildings.

Hourly emission intensity is a key metric for those policies and programs and in order to have consistency within the Commission on planning assumptions in all divisions, we're providing these preliminary projections for greenhouse gas emissions.

Presenting the GHG calculation method, key assumptions and projected greenhouse gas emissions at this workshop is mainly to give stakeholders and policymakers an opportunity to comment, and also demonstrate for you some of the key assumptions that impact these GHG projections.

COMMISSIONER MCALLISTER: Hey, Angela, can I ask a question here?

MS. TANGHETTI: Sure.

COMMISSIONER MCALLISTER: So Richard said about the

15 percent margin, and I guess I'm wondering how you're dealing with, you know, what's at the margin in this -- when you come up with hourly numbers? Do you know how much -- how much of that is -- what's happening in, you know, each hour in terms of gas that really needs to be there going forward?

MS. TANGHETTI: Yeah, we -- at this point in time, we haven't come up with a technique to calculate the marginal emission intensity, but what we do know is the system average in each hour. So given the portfolio that we have of imports, renewables, hydro, and how are the constraints on our system, we do know the system average in each hour, and we do know that by the end of the forecast period, in all cases, the midday hours are nearing zero.

COMMISSIONER MCALLISTER: Yeah.

MS. TANGHETTI: And the evening and shoulder hours are reminiscent of a, you know, the non-PVRPS, non-PV resources, thermal resources, some hydro, and imports.

So again, we do have a good handle on the system average, the marginal, we're still struggling with a technique to quantify what exactly what the marginal resource is.

COMMISSIONER MCALLISTER: Okay. I guess, so you're work -- I guess, in terms of what gets dispatched, you know, that's -- well, I'll just leave it there for now.

MS. TANGHETTI: Yeah.

COMMISSIONER MCALLISTER: But I guess just the -- that's something I think that we need to get to the bottom of because we're even funding some research on how we can narrow that marginal, you know, gas need. And kind of --

MS. TANGHETTI: Right. And we have been working with E3 on this --

COMMISSIONER MCALLISTER: Okay.

MS. TANGHETTI: -- in the context of the TDV updates --

COMMISSIONER MCALLISTER: Yeah.

MS. TANGHETTI: -- any kind of analysis there. We have been working with them. And we feel the system average may be a good indicator for the marginal that we may be able to use going forward. So we have some techniques that I think E3 at some efficiency in TDV workshops will be surfacing as well based on our simulation results.

COMMISSIONER MCALLISTER: All right. Great. And then you said exports had zero carbon and that's just because it's EIM solar? Or --

MS. TANGHETTI: We don't allocate -- the ISO does allocate emissions on exports because they are exporting to different parts of California from within their footprint. But if we're trying to assign emissions going out of California that we're exporting to our neighbors, it's the same thing again, we don't know exactly what is going out in those given hours.

COMMISSIONER MCALLISTER: Okay.

MS. TANGHETTI: So we just allocate whatever's generated in-state is our emission factor.

COMMISSIONER MCALLISTER: Oh, I get it. Okay. Thanks for that.

MS. TANGHETTI: Sure. Anything else?

Okay. So this table is just basically providing the numbers that underlay the graph on my previous slide. And a takeaway from this table is that greenhouse gas emissions from imports in the high demand case, it remains flat over the time, over the forecast period while the mid and low decline over the same period.

As Richard said, the mid demand case is characterized by meeting our RPS by about 70 percent of the resources being in-state and about 30 percent of our RPS is met by imported energy.

In the high and the low demand case we have a little bit different allocation. In the high demand case, we lean on our neighbors a little bit more for our RPS imports. And our low demand case, we have more of that energy allocated to California as -- besides relying on our neighbors. So again but to meet the RPS target in the mid and low case, we have about 30 percent or less from RPS imports.

And now with regards to an annual emission intensity projection. Emission intensity is an interesting and very useful metric that can also be calculated from simulation results. So emission intensity as we talked about a few minutes ago, in this table is in the annual tons of emissions divided by the energy serve load in California. And the value we show here is an annual average of the entire fleet of resources serving California's load.

The metric we show here is a system average annual however, this can also be calculated as we talked about on an hourly basis and that will represent the average greenhouse gas emissions for the mix of resources in any given hour. As expected, but not shown here, hourly midday emissions are nearing zero by the end of the forecast period. While evening and ramping hour system average intensities are more reflective of non-PV, renewables, storage, hydro, fossil fuel resources, and of course imported energy.

The 2019 IEPR later year system average emission intensity is lower than the 2017 mainly because of the higher RPS target.

WECC wide greenhouse gas emissions are more easily calculated from simulation results because you don't need to account for imported and exported energy. This is strictly a fuel use and emission factor calculation. Even though I say this is a simple calculation, this slide really had me scratching my head. I tried to put it on a graph at first, but there were too many lines crisscrossing.

So first let me go over the key drivers of why the 2019 IEPR WECC wide GHG emissions are lower than the 2017 IEPR GHG emission simulation results. First, 2019 IEPR has slow -- slightly lower demand projections for the rest of the WECC than the 2017 IEPR. Richard showed you that in a slide earlier. The 2019 IEPR has about 7,000 megawatts of additional WECC wide coal plant retirements than assumed in the 2017 IEPR. So recall coal generation has about twice the greenhouse gas emissions when compared to natural gas generation. And lastly, the 2019 IEPR has higher RPS targets than the 2017 IEPR, that is 60 percent compared to the 50 percent RPS target by 2030.

Okay. Now let's go over the 2019 IPER common case results, and these are what I've called to scratch my head results. Why does a low demand case have the highest WECC wide emissions while the high demand case shows the lowest greenhouse gas emissions in the early forecast years? The key driver here is these fuel price projects. Natural gas price projects are developed by our NAMGas team while our source for coal price projections is EIA's annual energy outlook, also known as the AEO.

The AEO does provide eight scenarios, reference case, high economic growth, low economic growth, high oil price, low oil price, high and low oil and gas resource, and technology. Looking at these eight pricing projections, we find very, very little variation over the forecast period between these coal price projections. Over the forecast period we find at most, at most, I'm saying is a dollar per MMBtu between the high and the low coal price projections. And recall the slide that Richard put together, they vary by about six dollars per MMBtu between the high and low cases.

With this great of a price deferential between projected coal and gas prices, we observe a greater utilization of the western coal fleet in the low demand which is the high price scenario and much less coal utilization in the high demand case. And again, I'm going to say this again, but coal generation has about twice the greenhouse gas emissions per Btu than the natural gas generation. However, by the end of the forecast period, the higher RPS requirements in coal plant retirements begin to suppress this coal utilization in the low demand case.

So with this, it concludes the key drivers and results for California and WECC wide greenhouse gas emissions that we have time to share today. We plan to share additional temporal results, possibly in another workshop during the 2019 IEPR. So with that.

MS. RAITT: Thank you, Angela and Richard.

So next is Anthony Dixon from the Energy Commission.

MR. DIXON: Good morning, everyone.

So I am here to talk about our data and structure of our NAMGas model. It is the North American Market Gas-trade Model, nice big word we call NAMGas, much easier to say.

So kind of basic overview, a simplified view of our model, it basic connects supply basins to demand nodes through transmissions. So gas is produced somewhere, it gets transported to where people need it. Model iterates between all these different components across all time periods and gives us prices, demands, supply, at a general equilibrium.

One thing to know, our model is North America so we have to encompass a little bit more than just California, WECC. Because the gas system is very integrated, we do compete directly for gas with the Northeast, with the Southwest, with the Midwest, so we really have to model all that because what happens in Northeast of course when we saw the polar vortex back in February 2014, when we lost gas here and then was very expensive for gas in the Northeast, they were paying a lot more for it. So they literally took gas that we normally would have had.

So here's our not so simplified view of the model. This is basically what the model kind of looks like and it's one -- this is one state. And so we do have the lower 48, Alaska, parts of Canada, and parts of Mexico. So kind of fun, we call it Tinker Toys.

So, the market builder platform is a general equilibrium model. It's been well vetted. We like this model. We use it very well. We've done some research on it seeing if this model or any others were better and we keeping coming that this is probably the best model that we can use.

So for 2019, some of the work we're going to be doing, we definitely reset the assumptions and -- for California. We use the Demand Office's numbers, we put them into our model along with the production cost model's numbers for the WECC. We've updated all the pipeline capacities throughout the model and projected what -- for can see what's going to be built. This actually kind of got changed just recently with some announcements for Mexico as their new president has kind of pulled back from investing into natural gas and wants to put more money into his -- into their coal -- their diesel fleet. And as we saw on many things, a lot of projects that were going to Mexico that would have exported gas especially from the Permian Basin in Texas is now canceled or delayed. So that kind of changed our modeling.

And probably one of the biggest drivers in this model and one of our biggest works we did this last off season, is we updated all the information for our natural gas reserves and potential gas in the cost curves for this cycle. And in a couple of slides I'll be showing you the results of that.

All our work is vetted out by a -- with our outside consultants and we really kind of keep going back and forth until we get results that are -- what we see would be reasonable.

So we also develop our three common cases built around the IEPR common cases. We have a high demand, low price; mid demand; low demand, and a high price case. All of our cases assume the Senate Bill 100 and that's partially because it's part of the WECC -- the production cost modeling and their power generation.

So as far as resources, which is one of the biggest drivers in our model, it's the assessment of what's technologically recoverable at certain costs of these resources, and the model distinguishes between a proved resource and a potential.

Proved resources, the capital costs are already sunk, they're not considered it's just the pipes -- the wells are drilled, oil and gas is coming out, it's just what cost it takes to keep producing. Our potential resources are ones that take some capital investment. There's drilling, seismic studies, things to find out where this gas is. So kind of the biggest thing as prices rise, more and more gas resources are -- become available because it comes more cost efficient.

And as I mentioned a little bit ago, we redid our cost curves for this cycle and as you can see over the year from 2007 which is the red line, to 2015 which is the green, and now the blue line which is our current updated models, we are producing a whole lot more gas at a whole lot less price. We are getting better at doing what we're doing. Part of this is the shale revolution, and the fracking, and the fact that we've been doing it for many years now so we're just getting better at it and finding better ways of doing it.

So the other big driver in our model is demand. So for -- we basically have to input four demands into our model. We have the nationwide model, which we refer to as Small "m," but after hearing Richard's presentation, I guess we need to up ours to at least a Mister or a Doctor or something. So Small "m" is a econometric based tool using EI -- EI historical data to produce the demands for residential, commercial, industrial, power, and transportation. And then we use the Demand Office's numbers for California and the production cost modeling for WECC. We override what the Small "m" model produces.

The next two slides kind of go over what the Small "m" -- the different sectors and what factors effect theirs. So as an example, for residential, you know, historical demand for natural gas, population, the price of gas, heating oil price which is a comparable substitute, and then our hot and cold weather, so the heating degree days and the cooling degree days all factor into our residential part of it. And here you can see commercial, industrial factors, and then here we have our power gen and transportation.

We also estimate elasticities in our model. We use the Baker Institute numbers that we've had for a few years now. And at the present time, we feel they're still very good numbers.

So, why we do this. We need to model the whole country or the North America because it can show vulnerabilities and possible opportunities in our -- in California for natural gas use. The market is very linked so we really have to keep an eye on what's going on in other places. Just recently we had the pipeline in Western Canada that went out -- that gas doesn't even come in to California, just to Washington and Oregon, and it caused price spikes in Northern -- all the way into Southern California and all the way into Texas from that one pipeline going out. And just kind of highlights how linked our whole natural gas system is.

So some of our initial starting quantities that we use in our model, we have a total for nationwide -- we have a total of 24 -- a little over 24 Tcf natural gas use in 2017 and of that, 9.28 is for power generation. And then the numbers for 2020 and 2030. These are just initial starting prices, once the model runs, it adjusts them as it feels needed for price and supply and all that fun stuff.

And then the -- like I said, the biggest driver in our models are our supply. And it's kind of the notice here that we are starting with 438 trillion cubic feet of natural gas proved, this is proved, this is what we know in the ground, what we very certain can get out of the ground. This is up about 35 percent from last cycle which was 324 Tcf. And this is also during a time when we're producing record amounts of natural gas. So we're pulling out more natural gas then we ever have out of the ground, yet we're finding more and more of it. It just -- there's a lot of it there.

And then for our model we're also having 65 gigawatts nationwide of natural gas being converted to -- for -- excuse me, natural -- of coal retirements being converted to natural gas. These are EIA numbers that we're using for that. And also, we use their numbers for the high and low case as well.

A few more of our initial starting data for potential reserves, these are the reserves that we haven't found but with some certainty and some investment we can find. So in all total, there's about 2800 trillion cubic feet of natural gas on top of that 400 trillion cubic feet of proved gas that we feel is out there. And these numbers come from the potential gas committee report produced in Colorado.

And then some more technology things, like we have the resources after tax, pipeline investments, income tax. And then our backstop technology which we never actually use in these iterations because the gas price is so low. But it’s basically if the gas were to hit $15 a thousand cubic feet, this is some kind of technology that would replace natural gas use or something just so it would be in there so if we hit something, we can.

COMMISSIONER MCALLISTER: Can I -- I want to ask a sort of a policy relevant question.

MR. DIXON: Yeah.

COMMISSIONER MCALLISTER: So is there -- do you have a way to consider a scenario in which the price is low or even lower due to a reduced demand of natural gas due to policies that are promoting electrification of end uses.

And I guess the reason I ask is because that’s in the -- that’s, you know, it’s definitely in the mix, there’s a lot of talk about electrification but it would be policy driven more than price driven, so it kind of goes counter to the structure of the model it seems.

MR. DIXON: Yeah. It could -- what we can do and its things we’re looking at because right now our model’s an annual model so it -- some of these things kind of average out. But what we can do with that and it’s something I actually am looking at for California is reducing the demands, keeping all the other things consistent but reducing those demands in California for all those different sectors down over the years and we can see what prices do then. So our outputs kind of is prices.

COMMISSIONER MCALLISTER: Right.

MR. DIXON: So, the -- the other costs, these are the costs that go into especially the supply part of the model.

COMMISSIONER MCALLISTER: Yeah.

MR. DIXON: So those might not change because they're more nationally set. But at least in California we can look at if natural gas is declining over the next, you know, 30 years to 2045 or whatever, we can see what the prices at our hubs would be.

COMMISSIONER MCALLISTER: Okay. Great. It would be nice to know sort of on that -- on the -- so you're talking about supply but on the demand side, it would be nice to know sort of orders of magnitude of, you know, a policy for aggressive electrification, what would that do to the -- to the -- to the demands, the various demand cases.

MR. DIXON: We can try and see what happens. I mean, there's nothing wrong with at least looking at it.

COMMISSIONER MCALLISTER: It might be totally at the margins --

MR. DIXON: Yeah.

COMMISSIONER MCALLISTER: -- but it would be nice to kind of know that.

MR. DIXON: Yeah. It's something we'd more than happy to look at.

COMMISSIONER MCALLISTER: Thanks.

MR. DIXON: So one of our other models that we do use, this is a -- uses some outputs from our -- from our NAMGas model. This basically takes our hub prices and breaks them up in to a format that our production cost modeling team can use. This is our burner tip prices. It takes the hub prices from NAMGas as a seasonality factor to them and transportation costs so you can get a -- basically in use of the natural gas that the power plants would use. The link on the bottom of this page is the link to the full report, Peter Puglia at our office developed this and it's been well vetted and well used and our WECC team and a lot of people really like this model so it's what we are using and.

And then some other uses for our model. As I just mentioned, the burner tip model which gets input into PLEXOS in the production cost model. We use NAMGas to produce our end-use natural gas rate forecast, our electricity rate forecast, transportation full price -- fuel price forecast, it goes into the cost of generation estimates, and various stakeholders also use this model as a part of their modeling and forecasting and also for other information sources.

And so for some of our next steps we're currently working on our preliminary results. We're -- we have a workshop scheduled on April 22nd to present those results and also the Outlook Report and I think we'll also be doing some production cost modeling, preliminary results might be doing that. And whatever else we're going to fit into that day.

So with that, any questions?

VICE CHAIR SCOTT: I had a -- excuse me -- I had a question a couple slides back here, let me see which one it was, where you are talking about in -- let's see, but it doesn't have numbers, it's the one that has the initial U.S. demand quantity, the proved reserves of approximately 438 --

MR. DIXON: Yes.

VICE CHAIR SCOTT: -- yeah, and then the coal conversions.

So when you are showing here the 2020 under the initial bullet, the 2020 and the 2030.

MR. DIXON: Yes.

VICE CHAIR SCOTT: This includes both sort of the anticipated growth in demand as well as the conversion of the coal plants?

MR. DIXON: Yeah. This includes everything nation -- and this is nationwide, so it's, yeah, it includes everything.

VICE CHAIR SCOTT: Okay. And so do -- are you seeing -- is that -- I'm just trying to envision in my head is that linear looking or does that tick up because of the coal conversions?

MR. DIXON: It's pretty linear. It's just a nice smooth like 1, 2 percent growth across everything every year.

VICE CHAIR SCOTT: Okay.

MR. DIXON: But once again, these are just initial so once we put it in the model when they apply elasticities, and the prices and things change, these numbers change --

VICE CHAIR SCOTT: Change as well.

MR. DIXON: -- change as well.

VICE CHAIR SCOTT: Okay. Got it. Thank you.

MR. DIXON: My pleasure. Okay.

Well, thank you very much.

MS. RAITT: Thank you. So, next is Lynn Marshall from the Energy Commission.

MS. MARSHALL: So hello, I'm going to discuss the methods and input assumptions for the preliminary and to some extent the revised electricity rate forecast.

So first I'll give an overview of the methodology and data sources. So, I'm taking data that the utilities submit on their projected revenue requirements, and then I'm combining that with our common case inputs. For example, on energy prices and cost -- carbon prices to construct scenarios of forecasted revenue requirements for all of the annual -- for all of the elements of a utilities revenue requirements. Then I'm combining that with revenue allocation factors provided by the utilities and our demand forecast to give me a forecast of sector rates for each utility for which we have data.

Then I'm calibrating those to actual -- recent actual rates so right now we have 2017 data for EIA, and for the revised forecast we'll have 2018. So calibrating the individual utility rate forecast and then constructing a weighted average planning area forecast, those are input in to our energy sector demand models and the south gen forecast, our transportation models are currently using a statewide weighted average. So that's the overview.

As was discussed earlier, we have high demand scenario combined with low prices and low prices -- and low demand with high rates. In addition to those, I'm combining the high demand scenario with lower distribution revenue requirements and conversely in the low demand high rate scenario. And I'll talk about that more later. So.

So first I'll -- so for the procurement costs. So I start by looking at the supply plans and the revenue requirements that the utilities have submitted and I'm using that to calculate how much energy they need to procure, what's going to be meet by resources currently under contract, how much new carbon free resources they will need to procure to meet their policy goal.

And then I'm using our wholesale -- staff wholesale energy price forecast to value what is going to be met by gas fired resources or any residual kind of generic market purchases.

So, to develop that wholesale price, I'm using our NAMGas hub prices, I'm using some results from our PLEXOS model so you can see as we approach that 60 percent carbon free by 2030, we have fewer renewable resources on the margin. So I calculated a market implied heat rate from the PLEXOS results, so we have that market heat rate declining over time, it's below -- by the end of -- by 2030, it's under 7000 Btu's per kilowatt hour. So that kind of moderates as you may say gas prices go up, that kind of slows the rate increase. And then also, our carbon credit allowance price forecast, and we go into the details on that.

So these are the hub prices, and the same hub prices that AJ was describing. This is showing them in perspective with some recent history. As you may have heard, there was some unusual conditions in the Southern California -- in Southern California gas system, but we're forecasting that we'll return to more equilibrium conditions in our mid case. So that's pretty similar to our 2017 IPER mid case.

And then you notice in the high scenario, we have pretty significant -- the low demand high price scenario, we have pretty significant increases in those first few years through 2023, that's 7, 8 percent annual increases and then it levels off. And conversely in the low demand high rate case.

So those feed directly into the calculation of the wholesale energy price forecast along with the declining market heat rate. So again we have prices dropping from their unusual -- unexpectantly high level this year to around what's -- this is so around $37 in 2019 and that's from what I've seen consistent with current forward market estimates.

Now you will notice if you compare this to the hub price chart in the low demand high price case, the wholesale price is not leveling off as much as the gas prices. And that's because of the carbon price scenarios. So I'll talk about that now. So Air Sources Board has recently adopted new regulations for the cap and trade market at legislative direction and part of that was to adapt -- adopt a firm price cap and then two intermediate price tiers. And so, the way it works is if -- when prices reach one of those tiers, reserve allowances are released through the market. So it's a natural slowing point for prices.

So the low -- or high demand low price scenario is unchanged, it's still at the reserve -- the floor price and that's pretty much where prices are right now a little under $16. What's changed is our low demand high price scenario. So previously we targeted the old -- soft cap, price cap in 2030 but now the structure or Air Resources Board regulations is such that they have set this red line which is a hard price cap, and if prices reach that level, they must make unlimited allowances available for sale and then they would take that money and go buy offsets.

So you can imagine they don't want to be in that position so they've set this hard price cap high enough that they estimate -- it's enough to incent investment in carbon reductions but not in -- high enough that it would cause undue economic harm. And they also estimate that it's highly unlikely that it would every reach that price cap.

So instead of using that for our high price case, we're going to use the Tier 2 price which is that green line. So that's about two -- so the Tier 1 price is -- starts off at about halfway between the floor and the cap. And the Tier 2 price is about three quarters in nominal terms between the cap and the floor.

So for the high price scenario we'll use the Tier 2 price and for the mid case, we'll use the Tier 1 price as natural slowing points for prices.

Do you have questions about that?

Okay. And I have sent this over to Air Resources Board just to get their check on it. We should hear back from them soon. Okay.

COMMISSIONER MCALLISTER: There are some -- I mean, there are -- there is some thinking going on for prices that are much higher than that and not within the ARB realm, but, you know, for example, over at the PUC and sort of for policy driving purposes. Now, that -- that's a different use case, right? But I guess I'm wondering how you sort of reconcile all these different conversations.

MS. MARSHALL: Yeah, there are estimates of sort of the social marginal costs.

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: That are much higher and actually the Air Resources Board discussed that. There are some new studies out that would indicate maybe prices should be much higher, but what we're using -- what we're using now is based on the current regulations through 2030 but it's possible if the generally the analyses comes in and showing that, you know, our market is functioning well in this price range or it gets to the cap. You could see them considerate that in the next round of regulations but I think this is what we got for 2030. So. Yeah.

COMMISSIONER MCALLISTER: Okay. Thanks.

MS. MARSHALL: Yeah. So okay.

Then for procurement that is needed to meet the additional GHG targets by 2030, I'm using PPA prices from our cost of generation model. So these show the wind and solar compared to what was used back in the 2017 IEPR, so due to declining technology costs, those have come down quite a bit. I think the solar crosses over the wholesale price around 2026 where solar's cheaper than the market price. So. And we'll be having -- I think expected to have an updated cost of generation report later this year. Okay.

So turning to the nonprocurement side of things. So as I mentioned, the utilities submit revenue requirements in a fair amount of detail so that includes distribution, demand response programs, energy efficiency and other publics goods charge, all their FERT costs, nuclear decommissioning costs, et cetera, et cetera.

So I review those for reasonableness and in some cases make some adjustments. So for example, PG&E has just submitted a new general rate case application, they'll probably include that in their submittal and we'll get this data till June. But then I'll see the rate payer advocate, the CPUC in a few months will make their assessment which will be less I would imagine than the full ask of PG&E. So I'll generally will make some adjustment for those years to come up to include a more reasonable outcome for the mid case.

And then I'm also looking at other developments and proceedings, advice letters, and CAISO transmission studies to see what else needs to be updated.

Okay. So then the one element of this that I do vary by the scenarios are distribution revenue requirements scenarios. And I'm starting right now, because I don't have new data submittals from the utilities, I'm working with the assumptions I developed for the 2017 IEPR. And so I looked at the range of possible spending just in total revenue requirements looking at transportation, projects, Edison has the largest in these scenarios because they had their -- fairly expansive grid modernization proposal.

So these will all be -- these assumptions will all be reviewed and updated for the revised forecast in particular looking at the wildfire mitigation plans that have just come out recently, there are some range of spending discussed in there. Edison now also has a grid resiliency proposal in addition to its previous application.

Develop -- there's also developments we want to be aware of in terms of transportation, building electrification, and climate change are also all things that could have implications for this distribation -- distribution spending component.

So just looking at, for example, PG and Edison here, San Diego's is a little out of date, I'm hoping they'll be a decision in their general rate case.

Impacts can range from -- these are annual real increases in rates from, you know, looking at 2 to 3 percent. So when you combine those with our demand forecast, so those 2 to 3 percent annual increase in revenue requirements can translate into 3 or 4 percent annual increase in rates.

So in the low demand high rate case with a lot of investment in the distribution system, that transcends into some, you know, 4 percent annual rate increases for SCE and PG&E. So, that's something I'll be digging in to more deeply for the revised forecast.

And that is everything. Do you have questions?

COMMISSIONER MCALLISTER: So on those, so obviously distribution rate is -- can be kind of a touchy subject and we don't do rate making. So I guess I'm wondering, you know, are you -- how closely are you working with your counterparts over at the PUC and on those -- just sort of getting a gut check on that stuff?

MS. MARSHALL: Well, I -- you know, I read carefully, like Ratepayer Advocates do a lot of good analysis of current rate cases. They do not do forecasting for obvious reasons. But they've been very helpful when I needed data. Actually, Ratepayer Advocates did have a proposal in the affordability OIR that they require the utilities to submit kind of short-term rate forecasts that would reflect the combined effects of all their applications pending. And that would be really valuable for forecasting because sometimes there are so many proposals out there, it's really hard to understand the combined effect of all those on even going two or three years out.

COMMISSIONER MCALLISTER: Yes. I guess, I'm just, I guess advise all of us to eyes wide open on this because we have the PG&E discussion, we have a lot of talk about how much the fire hardening is going to cost.

MS. MARSHALL: Yes.

COMMISSIONER MCALLISTER: And just lots of other exogenous factors, you know, from sort of what we typically do in a forecast that maybe we haven't looked at before or really had to think about before.

MS. MARSHALL: Yes.

COMMISSIONER MCALLISTER: And so, so we don't want to get crosswise with that process --

MS. MARSHALL: Yeah.

COMMISSIONER MCALLISTER: -- and sort of get out ahead and questions --

MS. MARSHALL: Right. Well, these are just scenarios.

COMMISSIONER MCALLISTER: Yeah. Yeah. No, I understand. For sure. I think probably when we have a joint -- down the road we have a joint workshop with our PUC counterparts, we want to work through that and just make sure --

MS. MARSHALL: Sure.

COMMISSIONER MCALLISTER: -- we're not making life too difficult for them but at the same time, are we being realistic on what we think's going to happen.

MS. MARSHALL: Yes. Absolutely.

COMMISSIONER MCALLISTER: Thanks.

MS. MARSHALL: Thank you. Okay.

MS. RAITT: So, we're just a little bit ahead of schedule, so I think from the dais we'd like to go on to the next presentation, and then we'll break for lunch after that one.

Okay. So, thanks. So, next is Dr. Konala on distributed generation.

DR. KONALA: Good morning, Commissioners. I'm Dr. Konala of the Demand Analysis Office, and I'm just going to be reviewing that inputs and modeling updates for the distributed generation forecast.

So today there's going to be three main areas that I'm going to cover. First, I'm just going to talk about updated input data that's going to be going into the distributed generation forecast and that includes updating PV installation data, and I'll be talking about new data sets that we're receiving this year. I'll also talk about updates to the non-PV self-generation data.

Afterwards, the second part of my presentation is going to be about modeling and methodology changes for the forecast. Specifically, in that section I'll be talking about incorporating additional achievable PVR AAPV into the baseline forecast for the 2019 IEPR.

I'm also going to be talking about updates that we plan to do on PV energy generation. And finally, I'll be talking about -- a little bit about energy storage as well. And I'm going to conclude my presentation by talking about the long-term behind the meter PV roadmap.

Okay. Moving on to input data. So here's just a brief model of the Energy Commission's PV model. And I just wanted to highlight the main inputs that go into our model. So the most important input is just collecting and then analyzing historical statewide installation PV capacity. We also incorporate economic and demographic data and specifically what we incorporate is projections for household count and commercial floor space.

We also consider the fuel price forecast specifically, the electricity price forecast and as -- and also natural gas forecast as fuels that are being avoided. Finally, we look at PV specific data including PV installation costs, PV performance, and other data related to photovoltaic systems.

Before I move on, I just wanted to do a quick historical recap of installed PV capacity in the state. This is just an update from the end of the 2018 IEPR forecast.

So for the end of 2018, we projected about 8,000 megawatts of capacity. We still don't have the final PV capacity data yet, but of the data we have, we're more than 80 percent there. So in the next few weeks we hope to finalize that number, and that will be the starting point for the 2019 forecast.

I also want to touch base on installation data. So this is a chart I presented in the last workshop in 2018, it was about where PV installation data came from for the 2018 forecast. I'm not going to spend a whole lot of time on to it, but I do want to point out the update or the changes that the new data sets that we're getting.

So in the 2018 forecast for the last year for 2017 data, we had to rely on the NEM Interconnection data set that is published by the CPUC. For the 2018 forecast, we will have the NEM Interconnection data available if we need it, but we plan to instead rely on two new data sets, the IEPR Form 1.8 which is submitted to the Energy Commission directly by some of the larger utilities in the state. And then a new data set, the CEC 1304-B data which is being reported by all of the different utilities.

So we have started receiving all of these different data, the CEC 1304-B data will take a little bit more time to analyze because that data is more of a raw form and we have to go through it, look at the accuracy of the data, and clean it quite a bit, actually. So depending on which data is more readily usable, we will be alternating between the 1304-B and the IEPR Form 1.8 for the preliminary forecast.

COMMISSIONER MCALLISTER: Sudhakar, what's the long-term plan as to -- I assume it's to rely on the 1304-B.

DR. KONALA: Yes.

COMMISSIONER MCALLISTER: How much work is that going to be, do you think, to sort of get it standardized and in a format that's it's more feasible to use?

DR. KONALA: In the long-term we hope that it won't be too much work. But for this year, it's going to be quite a bit of work because we're getting data in different formats from different utilities. Some of the data we were expecting to get was not all there so we have to contact utilities back and have them either resubmit it or at least ask questions about why it's the way it is.

COMMISSIONER MCALLISTER: Yeah, for sure.

DR. KONALA: Yeah.

COMMISSIONER MCALLISTER: I encourage you to elevate, if needed.

DR. KONALA: All right.

COMMISSIONER MCALLISTER: If you're not getting what you want.

DR. KONALA: Yeah. Thank you.

COMMISSIONER MCALLISTER: Thanks.

DR. KONALA: So yeah, we will be, we -- the exciting part is we do have more data and it is a lot more granular. In the 1304-B, we have information about the physical location about the PV systems that we've never had before. So it's going to allow for a much greater analysis and better forecasting ability going forward.

Okay. And I just want to show how the updated data that's actually effect the total historical data set. So for the 2018 IEPR forecast, we had up-to-date data from four of the five large utilities, but a lot of the smaller utilities hadn't submitted new data since December of 2016. And with the new data sets with the 1304-B and IEPR Form 1.8, we should be up to date with all of the utilities through December 2018. So this is quite a big update in terms of historical installed capacity.

Okay. So I'm going to move on to inputs for the self-generation forecast. So the self-generation forecast is essentially three different forecasts. We have the PV forecast which I've kind of talked about, then we also have the PV -- non-PV self-generation which includes a lot of different technologies in it, including gas turbines, gas reciprocating engines, wind, microturbines, and fuel cells. And finally, we have the storage forecast as well. So we'll be updating data for all of these not just PV, I mean, we did update it in 2018 but it's going to be a larger update.

So for the non-PV self-generation data, we will be updating it with 2018 data and that will be -- most of it will be actual self-generation data that is reported to us. We have two data sources where we get non-PV self-generation data. For large systems, we get it from CEC 1304, the QFER power plant data. And that is actually self-reported actual generation numbers. And for smaller systems, we get it from the self-generation incentive database or SGIP, those tend to be smaller systems and specialty fuel cells.

COMMISSIONER MCALLISTER: Are you assuming that basically every battery or fuel cell is a participant in the SGIP program?

DR. KONALA: For the most part, yes. Because the incentive at least for storage it's so high.

COMMISSIONER MCALLISTER: Okay.

DR. KONALA: But if there are some systems that don't report, then we -- we're not sure how on how to account for those yet.

COMMISSIONER MCALLISTER: Okay. So there's no -- there's no independent data source other than the SGIP for behind the meter storage?

DR. KONALA: Yes.

COMMISSIONER MCALLISTER: Okay.

DR. KONALA: SGIP is the only data source right now. In 1304-B for PV we did ask for other non-PV systems in that as well, but we have not had a time to go through that to see how that data is. So non-PV and storage systems are supposed to be reported in there.

COMMISSIONER MCALLISTER: Okay. Great.

DR. KONALA: But I haven't looked through it yet.

COMMISSIONER MCALLISTER: Okay. That's good. Work in progress, but let's try to make that happen if it's not.

DR. KONALA: Yes.

So one final point I did want to make about the non-PV self-generation is historical it's been kind of flat since 2014. So most of the growth in self-generation in the state is coming from PV.

VICE CHAIR SCOTT: Do you have a sense of why? Why the growth has been flat?

DR. KONALA: Most of the systems in the non-PV self-generation are large scale combined heat and power systems from the industrial sector and they just have not been -- start building any new ones.

Okay. So that actually recaps the major inputs, like the fuel price forecast and the economic and demographic forecasts we've already presented so I wasn't going to talk about it very much.

I do want to talk about some modeling and methodology changes that are coming for this forecast. The first one, which is the most simple one, is we will be incorporating the additional achievable photovoltaic adoption into the baseline PV forecast and possibly for the final time I just want to go over what the AAPV stood for.

So it accounts for PV system requirements for new homes based on the 2019 Title 24 standards. Our baseline forecast, it projects a certain percentage of new homes to adopt PV systems. And the AAPV forecast is just a difference between PV adoptions for new homes due to Title 24 regulations versus new home adoptions are in the baseline forecast.

So in 2019, AAPV will be incorporated into the baseline forecast. It doesn't mean that AAPV will not return in future forecast if there's new regulations that warrant us considering different scenarios. But I do want to point out the main implication of this. Incorporating AAPV into the baseline means that our forecast for PV adoption for new homes is now going to be based on regulatory compliance rather than a market forecast.

COMMISSIONER MCALLISTER: So is there -- is there no -- so but the market for retrofits is still continuing, right?

DR. KONALA: Yes. Yes. I'm talking about only new homes.

COMMISSIONER MCALLISTER: Only new. Okay.

DR. KONALA: Only new homes.

We will also revisit and update the assumptions for the AAPV forecast, this includes expect level of compliance and average PV system size for new homes. I believe in the past -- we don't have one single average, we have a different number for each forecast zone and home type, like depending on, like what kind of fuel they use. But we will revisit those assumptions after talking with, like the Efficiency Division and other stakeholders.

Now I want to move on to perhaps the more exciting part of this update methodology and that's updating PV generation. So historically array tilt, tilt being the slope of the PV panels such as, like the slope of a roof and azimuth information which is the orientation of a system north, east, west, south. So that information for PV systems was not available or not readily available and this has limited staff's ability to model generation because we have to make really simplifying assumptions.

But starting in 2016, the CPUC NEM interconnection data set has been reporting more consistent tilt and azimuth information for a larger number of systems. So here's a graph showing that this is directly an analysis of the NEM database and before 2007, there was no data. From 2007 to 2014 we were getting azimuth information on about 20 percent or less of the systems. But starting in 2016, we've been getting data on greater than 90 percent of the systems. Because of this we're more comfortable making some assumptions about the orientation of different systems for the state.

So if you sum up all of the years, we now have -- we now have orientation of about 65 percent of the systems in the state. So given that we have this information, we want to revisit how we look at PV energy generation and update the data to reflect some of the different orientation information that we have. So we anticipate this to be pretty intense process and it's going to take up most of our modeling efforts for the preliminary forecast, actually.

COMMISSIONER MCALLISTER: Do you have any -- do you have a sense of whether it's capturing more western afternoon solar resource?

DR. KONALA: I haven't analyzed the data year by year to see if there's been a trend -- a shift towards more southwestern facing systems, but over the course the entire data set that we have, most of the systems have been south facing.

COMMISSIONER MCALLISTER: Uh-huh.

DR. KONALA: So I anticipate going forward more and more will be southwest facing, but I haven't seen -- I haven't compared the 2018 and 2017 data to previous years to see if there's been a shift.

COMMISSIONER MCALLISTER: Thanks.

DR. KONALA: So I'd also like to move on to energy storage now. So we do an energy storage forecast but forecasting storage has been actually quite difficult over the last couple years. The main issue is that storage data is limited, there weren't any systems installed before 2011 of consequence. And even for the systems that were installed, a lot of important data was not available. For example, the storage capacity in kilowatt hours has only been available for the last two or three years.

So in SGIP only the power rating of the system was reported and not the storage capacity and capacity is very important.

So another challenge and I'm talking at this without the incentives, but residential storage is not yet econo -- economically competitive by itself. It is a little bit more competitive when we look in -- when we look at the incentives. But because it is not that competitive, it's hard -- it's difficult to model it.

So when you look at the historical data, most of the storage systems they've been sold by installers as paired with PV. And what's essentially being -- what is essentially being done is that some of the economic benefits of PV have been transferred to a PV plus storage system and that's how adoptions have been occurring. So going forward, we have to look at how much sense PV plus storage -- how much sense it makes versus PV alone when we're modeling storage.

So we plan to revisit this because until this point because data has been limited and we haven't had a lot of information about system size, our storage forecast has essentially relied on a trend analysis, looking at historical trends and then forecasting them forward.

So because of the work for PV energy generation, we expect that a lot of this work will be delayed until the revised forecast. But by the revised forecast, we really want to revisit and analyze in the competitiveness of PV verse -- PV plus storage versus PV alone when forecasting storage adoption.

And a second aspect of updating the energy storage model is we plan to build an hourly storage model so we can incorporate the effects of storage on peak demand.

Okay. If there aren't any questions.

VICE CHAIR SCOTT: I do have a quick question.

DR. KONALA: Okay. Yes.

VICE CHAIR SCOTT: So this -- is this type of data also, I forget the number of our new form, the 1304-B was it, is that -- is that -- will we be collecting this type of data as well through that form or other forms?

DR. KONALA: Not yet. So in terms of storage capacity --

VICE CHAIR SCOTT: Uh-huh.

DR. KONALA: -- in the original regulations, we did not ask for storage capacity.

VICE CHAIR SCOTT: Oh, I see.

DR. KONALA: But we hope to ask for it in the next set of -- next round of rulemaking.

VICE CHAIR SCOTT: Okay.

DR. KONALA: So right now we requested it as an optional field but if utilities don't feel that we don't, we can't enforce it.

VICE CHAIR SCOTT: Okay. Thanks.

DR. KONALA: So I'm going to move on to the long-term PV forecast roadmap if there aren't any questions with the modeling changes.

VICE CHAIR SCOTT: I -- one other question I have and maybe it's for the transportation conversation that's coming up this afternoon.

DR. KONALA: Yeah.

VICE CHAIR SCOTT: How are we taking into account electric vehicles and sort of vehicle grid integration and the -- their storage capability that they will have? Or should I save that for transportation?

DR. KONALA: I think you should save it for transportation.

VICE CHAIR SCOTT: Okay.

DR. KONALA: But I might have to chime in during that part a little bit.

VICE CHAIR SCOTT: Sure. Because, I mean, it fits a little into the distributed generation as well, right? But not --

DR. KONALA: Yes. Yes. I do want to say that obviously energy storage and storage in vehicles, they're related but the cost structure is different when you look at it and it's a lot more expensive right now for actually stationary storage.

VICE CHAIR SCOTT: Okay. Thanks.

DR. KONALA: Okay. So quickly moving on to the roadmap. Of course our long-term plan is to move to a new model that is being currently developed by the National Renewable Energy Laboratory. The model is called Distributed Generation Market Demand Model or dGen for short.

Just a quick review of, you know, how the model works. It's a bottom up market penetration model. It stimulates potential adoption of distributed energy resources for residential, commercial, and industrial entities in the U.S. and it does this by modeling representative agents in each sector.

And the real advantage of dGen is that it's capable of producing a more disaggregate geospatial forecast compared to the model we have now. They're -- they are already able to forecast at a county level and they should be soon at a census track level. Whether we can do a forecast on a census track level is a different -- a different conversation because there are a lot of inputs that have to go into that level of forecast. But at the very least, they're already at a county level and we have good data at the county level.

And just to review of the dGen contract. So the Energy Commission sought an improved forecasting ability for PV, and they contracted with NREL to adapt dGen to model a California market. This contract was approved in the January 2017 business meeting. And it is going to deliver modeling results to the energy commission.

We had an early preliminary delivery in the end of 2018 but they will be delivering results in 2019 as well. And I want to go through that in the next slide.

So for our plan utilidas -- utilization of dGen. So for the 2019 preliminary PV forecast, we plan to run our model and concurrently NREL will be running the dGen model. Around the time that -- around the time when we are expected to finish our modeling results, NREL staff will deliver results from dGen specifically for PV to the CEC. And we will present both results from our model and from NREL concurrently at the same time at our preliminary workshop.

Afterwards, NREL will continue to work on dGen modeling work to make any final revisions and improvements that we think are necessary.

And then for the 2019 revised forecast, we will do the same thing, we will run our model and NREL will run dGen, and then NREL's results for PV will be delivered to the Energy Commission. At this time the official contract for dGen is completed and NREL has delivered what was promised on the contract which is to run the model and deliver -- to deliver results.

Then in 2020, NREL will be using funds from a grant from the U.S. Department of Energy to open source dGen. And when that is complete, NREL will be transferring -- or making dGen available to the Energy Commission so we can start looking at it. In the meantime, in the 2020 IEPR update forecast, DAO staff will continue to use the CEC model but we probably won't have access to NREL's dGen model at the time because it's out of contract.

Once we receive the dGen model from NREL, we will start using it and by 2021 IEPR forecast, DAO or at the Energy Commission expects to run dGen itself and we can use the modeling results from dGen to inform our forecast fully. So this is a long-term plan for the PV forecast going forward and I just wanted to bring that to the Commissioner's attention.

So this actually concludes my presentation but if you have any questions, I'd be more than happy to answer them.

COMMISSIONER MCALLISTER: So on dGen, I mean, I assume you're looking -- you're calibrating to the market each iteration?

DR. KONALA: Yeah.

COMMISSIONER MCALLISTER: I mean, are you backcasting and making sure that it's reasonable and everything?

DR. KONALA: They are backcasting. I have not seen the backcasting results but in communication with the NREL team, they feel like the backcasting results have been pretty promising.

COMMISSIONER MCALLISTER: Are they going to teach us how to do that when we take over?

DR. KONALA: I think they will teach us -- the contract actually ends around April 2020, so any teaching that they do will have to happen after they finish the runs but before the contract ends. But there is some -- in the scope of work it does specify that they will teach us somewhat.

COMMISSIONER MCALLISTER: Great.

DR. KONALA: Okay.

COMMISSIONER MCALLISTER: Thank you.

DR. KONALA: All right.

MS. RAITT: So I think that's it for the morning presentations. So if you like, we can go ahead a take a break until 1:00.

VICE CHAIR SCOTT: Sounds good.

COMMISSIONER MCALLISTER: Perfect.

VICE CHAIR SCOTT: Thank you.

[Off the record at 11:55 a.m.]

[On the record at 1:01 p.m.]

MS. RAITT: All right. Welcome back. We are going to start the data input assumptions workshop, the afternoon portion on transportation. And Matt Coldwell's got a few words for us.

MR. COLDWELL: Welcome back from lunch. We're going to shift gears to transportation, pun totally intended there.

So I'm Matt Coldwell with the Demand Analysis Office. And so before we start with the scheduled presentations, I just wanted to highlight just something that we all know, right, is that the transportation sector is dynamic and it's transforming in ways that make forecasting it quite complex. And so for example, automakers continue to make announcements of new electric and hybrid electric vehicles. Our sister agency, the Public Utilities Commission, has already authorized 1 billion in transportation electrification infrastructure spending for the investor owned utilities through 2023. And there's another 1 billion currently pending CPUC review.

Electrification of municipal and school bus fleets, electric and fuel cell, electric off-road transportation -- off-road transportation equipment at ports, airports, and warehouses, innovative transportation business models such as car shares, electric bikes, or electric scooters, land use policies that focus on urban densification and public transit, and technology advancement, you know, autonomous vehicles, and to your question earlier, Vice Chair, about vehicle to grid applications.

So these are all things that are currently happening in the transportation sector and certainly add to the complexity of trying to forecast throughout the 2030s. So the truth is in 2030, the transportation sector is going to look a lot different then than it does today. Even in 2025, it'll probably look a lot different than it does today. So the transportation forecasting team is trying to capture all that, the dynamic nature of the transportation market.

And so we're currently doing that. And I just one of the main things I wanted to note before we get into the presentations is that we're planning having a workshop on a lot of these emerging transportation issues later this summer, I think, in the July timeframe if I remember right, don't hold me to that. And so topics such as vehicle to grid and how that's being incorporated into our transportation forecast, land use planning policies, urban densification, and of course all electrification both in terms of the light duty sector and our medium duty heavy duty sector as well.

So these are all things that we're working on, you know, we're monitoring it, we're participating in working group meetings, and ultimately it's our job to sort of reflect that in the transportation forecast moving forward.

So today we have a few presentations on transportation inputs and assumptions. Ysbrand will be doing a presentation on transportation fuel price forecast. We have Mark will be doing a presentation on some of our base year inputs and assumptions. And then we also have a really exciting presentation from K.G. Duleep from H-D Systems who we have contracted to update and refresh our vehicle attribute assumptions, both for light duty -- both for the light duty sector and also the medium duty-heavy sector. So he'll be talking a bit about that.

And so I think Ysbrand is first; is that correct? Okay.

So thank you for letting me interrupt the meeting. And here's Ysbrand.

MR. VAN DER WERF: Okay. I am Ysbrand van der Werf, I am talking about the fuel price forecast that will be used in the 2019 IEPR.

And the fuel price forecasts are particularly important as an input because vehicles consume fuel, fuel costs money, obviously, and as fuel becomes more expensive, consumers tend to switch to vehicles that consume less fuel. So for instance, as the price of gasoline goes up, consumers tend to buy vehicles with better gas mileage. And similarly, as the price of gasoline goes up, we might also expect consumers to buy more electric vehicles. So in that sense, gasoline and electricity are substitutes for each other. So that is -- it affects vehicle mileage and the choice of fuels.

And the -- the process I go through for these forecasts is I generally make California adjustments to nationwide forecasts that are prepared by the Energy Information Administration, EIA. I apply these California adjustments to the national prices. I do not make a forecast specific to California. And a staff proposed to use three scenarios from EIA's annual energy outlook. Their referenced price, their oil low -- their high oil price and their low oil price scenarios, and we supplement that with EIA's short-term energy outlook for 2019 and 2020.

And for natural gas and electricity, we consult with Energy Commission experts, we heard about that this morning. And for hydrogen prices, we consult with experts from NREL. And the jet fuel price, that forecast is very easy to do because historically California jet prices have been almost identical to the national average of jet fuel prices. So we simply use EIA's nationwide forecast.

And E85, the price forecast for that is also easy because we assume that on an energy equivalent basis, the price of E85 will equal the price of gasoline. And over the course of, you know, weeks or months, we might expect one fuel to be more expensive than the other but, you know, we're looking at annual average prices here and right now those two fuels, they're both used in flex fuel vehicles. So on an annual average, the prices will have to be about the same or one fuel will simply drive the other from the market. And we also hope to solicit expert advice from workshop participants.

So now what is the California adjustment? And as I'm sure everybody knows, California fuel prices are typically higher than those in the rest of the country and this adjustment, it's actually a number of adjustments that each of which contributes to the overall higher price for California fuels. So each explains how one particular aspect, say difference in taxes, influences the price of California fuels, how that makes them different from the nationwide average. And another one is the cost of crude oil paid by California refineries.

And many of these factors can be quantitatively predicted based on historical values. And today we will be discussing primarily gasoline and diesel and I'll also touch on propone just a little bit.

So in the past, this forecast used to look at crude oil prices, not fuel prices. But here we see that they really tend to move very similarly. The dark line, the lower dark line on both of these graphs is for crude oil, the price paid by refiners. And the orange and blue lines are the price of -- the retail price of diesel and gasoline. And they move -- the movements, they're all very similar. And there's really no reason to use crude oil as a starting point because in order to develop California fuel prices from a crude oil price, that would make it necessary to forecast the cost of refining, and EIA has already done this by preparing their fuel coast forecasts. And in general, they have far more resources available for this sort of activity than we do. So we want to make use of any work that they do.

Now the specific method in forecasting the California diesel and gasoline prices, as I mentioned, I use past prices and relationships to predict future prices. And in doing so, I assume that these relationships between prices will continue in the future. Specifically, the California price is forecast with an ordinary least squares regression using annual historical data.

I have only 15 years of the necessary data, but, you know, ideally I'd like to have at least 30. But I confirmed these results by carrying out the same analysis with monthly data. So I had 180 months, 180 observations, and I got essentially the same results. Propane, however, has much less data available and the analysis just can't be as rigorous.

And the specific variables I use in forecasting the California fuel prices are of course the U.S. gasoline or diesel price, plus this list of California adjustments. The California sales tax appropriate for gasoline or diesel, the

California excise tax for gasoline or diesel, the underground storage tank fee, the low carbon fuel standard credit price, and the carbon allowance price which we also heard about earlier today. And then I include the difference in the refiner's cost of crude. And lastly, I have a variable to account for the outage at the Torrance Refinery and that is used only for gasoline.

So starting off with the California adjustments, the simplest one to tackle is taxes. So the forecast used is current and future fuel taxes obtained from the California Department of Tax and Fee Administration. And a couple of notes here, you can see that the table on the right, one thing that stands out is that the sales tax on diesel is much higher than the sales tax on gasoline. And going forward beginning next year in 2020 on July 1st, the excise taxes will be adjusted for inflation initially. So that's easy to account for since I do all the analysis in real prices anyways. And second, the assumption is that sales taxes and the underground storage tank fee do not change.

Now, another feature unusual in California is the carbon allowance and the LCFS credits. The carbon allowance price is a price ceiling and a reserved price, as we heard about this morning from Lynn Marshall who forecasts those prices and those are incorporated here. The LCFS credit price, LCFS, low carbon fuel standard, has a soft cap which is used as the high scenario price here.

Now on the graph on the right you see there's no line, there's no data on the graph until 2013 because these credits really -- they did not exist. And then the blue line, the carbon allowance price, that's been pretty much flat. I mean, it's only varied from 12 to $15 for its existence. And the LCFS credit price, on the other hand, has increased a lot. But it's important to remember that the allowance, the carbon allowance and the LCFS credits work in different -- work in different ways. So this price is not necessarily an indicator of relative compliance cost.

Now the fact that these two programs began, were initiated -- well, the credit and allowance prices kicked in in 2013, both of them, that makes it hard to separate out their individual impacts on fuel prices.

Another factor that many people don't know about is that California refiners pay more for crude oil compared to the national average. This is at least in part due to the fact that shale oil, which is very inexpensive, is available to refineries located east of the Rockies, and that accounts for the peak seen in 2012 and 2013. But this past year -- excuse me -- will reach an even peak and that is there is an additional factor that's kicking in and that is the California refiners process more heavy crude oil than the national average.

And as the decline in Venezuelan production has occurred over the past few years, their production has fallen by 50 percent in three years. And with Canadian production cutbacks, the price of heavy crude oil has increased. For example, in January of 2018 the price of California Wilmington Crude oil produced here in California, traded at a $3 discount to West Texas Sour. But then a year later in December 2018, it traded at a $6 premium to West Texas Sour. And in between there during the summer, it got as high as an $11 premium.

So and -- now this graph is the more general than that, it's the West Coast average price versus the national average. And this peaks at about above $6 for the annual average of 2018. But in November, it got as high as $9.30. So this is really an underappreciated reason for California gasoline and diesel prices being so much higher than the national average right now.

And another factor is California refining costs are high. This isn't as big a factor as the -- as taxes or the cost of crude oil. But the cost of producing gasoline that meets California specifications is high. And this graph here, this assumes a typical California mix of refined products. It's a 3-1-1 spread. So three -- five barrels of crude oil will produce three barrels of gasoline, one barrel of diesel, and one barrel of jet fuel. The California refining spread, the dashed red line is most of the time higher than the U.S. refining spread.

And this spike, you see the -- in 2015, the dashed red line for California has a spike up, that coincides with the outage at the Torrance Refinery which was then owned by Exxon Mobil. And this works out to an average, I do it here in dollars per gallon. It varies from zero to 22 cents, the average is about 8 cents per gallon.

Okay. Now moving on from the California adjustments. We have a little information about crude oil production just to provide a little context here. And the blue line is -- the blue line on the graph is a U.S. production that uses the right axis so it increases from about 9 million barrels per day to 12 million barrels per day, a 3 million barrel per day increase over this three-year period. And the dashed red line, that is the sum of OPEC and Russian production and that uses the left axis, and that stays pretty much between 44 and 45 million barrels per day.

Now each -- so the scales are different but the change -- so the horizontal line, the horizontal grid, each one steps up by a million barrels per day. So you can see, U.S. production has increased by a lot more than OPEC plus Russian production in this three-year period. And in 2018, U.S. production increased by 1.8 million barrels per day compared to just 0.7 million barrels per day for OPEC and

Russia.

So against this backdrop of rapid increase in U.S. production, well, we're facing a possible -- well, there will be cutbacks in 2019. OPEC and non-OPEC countries, including Russia, have agreed to cut production by 1.2 million barrels per day starting January 2019. And the province of Alberta has also announced cuts of 325,000 barrels per day. They've already reduced those. Then, as I mentioned earlier, Venezuela has seen substantial cuts over the past three years without any sort of sanctions. And Iranian production is about the same as it was at the beginning of this graph period, but in between, their production really picked up as sanctions were lifted, but then their production declined again as sanctions were put back in place. But it's likely that that will decrease as well.

So the takeaway from this is that looking forward, we've all heard about the prospect of production cuts by OPEC and others, but we have the backdrop of rapid U.S. oil production, rapid increase in U.S. oil production, and so we shouldn't expect to see a big fall in global production or a corresponding increase in the price of crude oil.

And that leads us into the actual predictions here. This is the forecast price for gasoline, the historical prices in red. Then we have three scenarios in green, blue, and black. And while gasoline is primarily a fuel for light duty vehicles, diesel which we see on the next slide here is a fuel for -- well has been primarily a fuel for medium duty and heavy duty vehicles. And if we go back, we can see the price -- the dashed green line up at the top, the price in the high crude oil price scenario, it stays below $5 all the way out to 2030. But diesel goes above 2030 in about 2025.

And one reason for the diesel price to be expected to be higher is what's referred to as IMO 2020. And that is effective on January 1st, 2020, the International Maritime Organization, IMO, has cut the worldwide sulfur limit for marine fuel from 3½ percent to ½ percent. So that's an 80 percent cut overnight.

Now the means of compliance with that are varied and there's a lot of uncertainty. But in the near term, at least, the demand for diesel fuel to blend with marine fuel will likely increase. So refiners will increase their production of diesel and the price of diesel will likely increase. But at the same time, there will be an even greater increase in the production of gasoline so the price of gasoline should not increase as much as the price of diesel.

And lastly, we have here the forecast for the -- the preliminary price forecast for propane. There's no historical data here because there really isn't anything available to put on this graph.

And that concludes my talk.

MS. RAITT: Thanks.

Next we have a presentation from K.G. Duleep from H-D Systems on vehicle attributes and market trends.

And I should just mention that this presentation is slightly different than the one that's posted online and is in the handouts but we will be posting this revised version.

Thanks.

MR. DULEEP: Thank you. Good afternoon, Commissioners, and thank you for having me.

What I'm here to talk about is the work we're doing to support the CEC's modeling effort. And we provide the vehicle attribute forecast which provide information to the California demand models on how vehicle technology will change, how the performance will change in weight and cost and size. And all this is done at what we call a market class level which groups individual sizes and get consumer perceived classes of vehicles.

We've had lots of experience doing this, we've been doing this since the 1990s, and we've also supported the Department of Energy's EIA's NEMS transport model of field demand historically. And what essentially our modeling effort is is the supply side of the modeling industry and how they'll respond to the demand and the regulatory framework.

And one issue that I should mention is that the models, our model and the California Energy Commission's demand model don't really talk to each other dynamically so that that interaction has to be done at a people level. Now what we try and do doing the updates is to look at what big issues are coming up on the supply side. And of course the big one, the elephant in the room is, of course, the Obama standards either for fuel economy and greenhouse gas. And the current administration as you probably have heard wants to hold the fuel economy standards constant beyond 2020. And California has stated its intent to continue the existing regulations. And that's, I think, a difficult issue to handle in the modeling framework because there's lots of possible outcomes.

The national standards, the (indiscernible) national standards could be imposed on California. You could have two different standards, one for the nation, one for California. Or else California could prevail in the courts and the old national standard could continue. And so we're sort of faced with that and will have to handle that probably in a scenario basis.

A second issue which I think has been alluded to a little bit earlier is the future of electric vehicles. Everybody's putting out very bullish and optimistic forecast about what electric vehicles are going to do and of course international autonomous vehicles is yet another factor that might complicate the entire forecast.

One reason we wanted to look at this issue of what Trump Administration has proposed to the CAFE standards is that they have claimed in the new standards that the revised standards be substantially better for the consumer relative to the whole Obama Era standard which is called the 54.5 mpg standard. And the proposed standard that the Trump Administration's put forward is to stop any further change in the standards beyond 2020. So essentially next year standard would hold good for the 2020 to 2030 period.

And what we found is that there was regulatory analysis of the new standards put out by the Department of Transportation. And the claim was that the new standards would be met at an incremental cost to price to vehicles of $700. Whereas if we stuck to the Obama standard, the claim was the average cost $2,650. In effect, a couple of thousand dollars more of cost added for the small differential in fuel economy.

And to put that in perspective and this analysis was done perhaps two and a half years ago, right before Obama left office that the differential was almost twice as large as what was estimated earlier. And so that's been a major issue. And one of the reasons we wanted to look at that from a little bit of detail of standard, there have been significant changes in the cost of technology. Because as you know, the way future standards are met is through technology improvement of vehicles.

We did look at that and I noticed a little bit of a busy graph but if I may point to you to a couple of lines here. The second line says what is attained corporate average level for all vehicles. And so under the existing standards, even though they're called 54.5 mpg standards, the real fact is that there are many other things credits and so on that they'll actually attain only 46.4 mpg and 45.7 mpg in 2025.

And then the proposed standards, what DOD is claimed is that even though they freeze the standards at 2020 level because manufacturers already have all these plans in motion, they wind up actually exceeding the standard and get up to 39.2 miles per gallon. So essentially you're looking at something about six and a half mile per gallon differential between the two standards. And that differential is what's going to cost the consumer the claim was a couple of thousand dollars in additional vehicle retail price cost.

And the voluntary -- and when we looked at this, we tried to start to look at it in detail as to what are the changes that's causing this huge differential in cost and so on. And what we found is that if you start to adjust everything to the same basis and make the same assumptions, if you use the old analysis, the 2021 through '25 standards would cost only about a thousand dollars was the initial estimate. But interestingly enough going from 2016 to 2020, the new cost and the old cost were not that different, their $700 was to $750. So within the range of error.

And I think if you look at this -- anyway, I'm sorry. Let me just check. No, that's fine. I'm sorry. I just had one more slide than I intended.

So essentially, I come in turn the slide there. So there's little change from the 766 forecast in the earlier times to about 700. And what we did was look at this, looking at the 2021 standard. And what we found was that the overall differences for meeting 2020 or 2021 standards, because of the overcompliance issue, we had to look at 2021. What we found, there were -- the technologies used in the new analysis and the old analysis were quite similar that yeah, they had a little more turbo charged engines, little less weight reduction, but on the whole, there were not huge differentials. But also there was not very much change in what -- what was estimated to require -- to be required from hybrid PHEV or EV penetration forecast.

And so essentially what we did find was for the 2020, 2021 standards, the technology, underlying technology assumptions were not substantially different. So you can see why the costs came out reasonably similar. But then when we looked at 2025, we found they used a lot more hybrids to meet this 2025 standards and the existing conditions which I countered for much of the cost differential. But in addition, the change, the retail prices of hybrids enormously, almost a factor of 3. And here I've listed some of the old assumptions from 2016, some of the new assumptions from 2018. And just to bring to your attention, the strong hybrid which is the bottom line on this is in the old analysis, that was assumed to cost somewhere in the $3,000 range. And the new analysis, it cost $8,000.

And what we found, of course, is that there's very little analytical backup to go for this new $8,000 claim for the strong hybrid. And just to give you an example, of course, the Prius is one of these and it's been in production for, oh God, for 20 years. And so the cost of these technologies is reasonably well-known. And why this change was made is quite difficult to ascertain.

And so what we concluded from the review was that we don't really need to change very much. What we did find was that under the Trump Administration, many of the low-cost technologies would either ignore, they reduce the effectiveness as to what was previously known but unfortunately, there was not a lot of actual data to back this up. And in addition, as I mentioned, the use of hybrid technology was increased enormously, both in terms of cost and market penetration. And as a result, these cost numbers have changed dramatically but the underlying estimates we believe were inconsistent to what we actually observed in the market. So there’s not -- we don’t see any significant changes regard for the Energy Commission forecast of retail prices. We want to keep them reasonably same as what was done before.

The other issue for light duty vehicles is electric vehicles. And here we perhaps suffer from neglect of too much data and there are obviously as you read in the newspapers very aggressive cost reduction forecast and so on. And of course the cost of the battery is the big driver in EV prices.

One of the things about this public forecasts is they’re sometimes very skimpy in detail. And a battery starts from a cell, a single cell, and then they’re assembled into modules. And then all of these modules are then connected to make an entire automotive battery which is actually a fairly complicated thing because it needs a safety system, it needs a battery monitoring system, it needs a cooling system, it needs a crash protection system. And so we’re not showing all the costs of the entire battery of being counted in some of these public estimates. And numbers are thrown about and they could refer to either cells or modules or batteries or batteries without some of these systems. So we don’t -- we don’t this.

I think that we’ve obviously read in the newspapers and in the financial journals about current batteries costs being around $150 per kilowatt hour. But what we tried to do was to look at Tesla’s own financial results, and they’re probably the leaders in battery technology and in the cost of batteries. And if you looked at the financials and broke that down, we think their costs are roughly $230 per kilowatt hour last year. Because as you know, they’re having trouble with making money on a $45,000 Model 3 and leave alone a $35,000 Model 3.

Of course cost reductions are 40 to 50 percent maybe possible by 2030, but that might be at the high end and it depends on what number you start -- start from. As was done I think in the last IEPR, we’re going to handle some of these different cost number estimates on scenario basis, how much decline can be expected, what the range can be expected. But we hope to include a realistic range of prices rather than pie in the sky type forecast.

Of course another issue is how much battery you put into the vehicle, what kind of range you want. And we’re trying to figure out where the industry’s heading on this, it looks like everyone’s going to the 200-mile, 250-mile level, but at the same time you also hear about some new smaller vehicles that might be introduced primarily for urban driving which might get by with a 100-mile range.

On the issue autonomous vehicles, most people believe that Level 4 or Level 5 autonomous vehicles will enter the market. And I think it's just a matter of time, I'm certain that it will. What is not widely known is there's an awful lot of stuff on the car, RADAR, LiDAR, vision systems, lots of computers and they actually require a lot of electric power. Right now those systems consume over 2 kilowatts of power. And it may come down, of course, with as most things improve in the future. But regardless of high-level of electric power demand means that most of these autonomous vehicles are likely to be either hybrids or electric vehicles because they have to have an underlying power grid to support that kind of high level of power.

So from that sense, that may also be a driver for hybrid and EV sales. The fact that both of them might have favorable synergies.

We do continue to model-- I did the alternative field vehicles and we look at -- we're looking at E85 and hydrogen. And from a supply side perspective, E85 vehicles are currently called flex field vehicles. And there were a lot of models that were available up till fairly recently but the -- and the reason that they were there in the fleet is that the manufacturers are responding to a fuel economy credit for CAFE compliance. And that credit is unfortunately being phased out and it will go to zero by 2020 and so the number of flex fuel vehicle models is dropping sharply.

And our own estimate is that very few models will be available. They may continue to be some small number of models available after 2020. And that decline, as I mentioned, has already started.

Fuel cell vehicles that use hydrogen also have a difficult forecasting issue. Since most automotive technology depends on obtaining economies of scale, so unless you make a hundred thousand of them, it's hard to get costs under control. And when I think the fuel cells have their work cut out for them because they're facing a lot of competition from longer range EV models, they face a lack of hydrogen infrastructure and so on. So it's not clear what the path to high volumes would be. Fortunately, I don't have to do that, I'm on just the supply side of the cars. And I think it's CEC's difficult job to figure out what scenarios might be applicable to that area.

But really, the main issue would be how to come up with low-volume production, high-volume production based cost estimates and see how that can be integrated into the forecast.

For heavy duty vehicles, we're modeling a wide range of heavy duty classes and field types. These models were updated two years ago and even though this is less widely known, there's also a requirement for greenhouse gas reductions from heavy duty vehicles. So the technology is actually be driven by regulations even in this market. And -- which is fortunate for us because the technology driver -- driver is principally regulatory and those can be modeled at some degree of certainty.

One of the major issues is that there's a lack of a well-defined baseline for fuel economy and cost. And that's because there's no fuel economy standards or measurement procedures or advertised numbers for trucks. And historically, that used to be done through a survey by census. And census, unfortunately, canceled that survey a couple of decades ago and so there's very little data on this issue.

And there was a recent survey collected -- conducted by CalTrans but they didn't collect data on fuel economy, just on travel. So that area of uncertainty will continue to plague the forecast. We try and approach it thorough more limited sets of surveys or by fleet reports of data and so on. And -- but we recognized that there is an issue in terms of how represented this could be.

One area that we are going to reexamine from the 2017 forecast is the emergence of large electric trucks. I think Tesla is talking about a tractor capable of hauling a typical 50,000-pound GVW trailer. And so we were trying to see if that could be included in the model.

There's also a requirement for us to model CNG and LNG trucks. And we've been looking at this market for decades and I think the problem is that have a very disappointment market growth even when diesel fuel prices were very high, they didn't manage to get very much market share. And part of that is that there's only one game in town and that's Westport. So Cummins-Westport makes one side of engines. And more recently, Westport has joined with Volvo to make another type of CNG and natural gas type engine.

The Cummins-Westport engines use spark ignitions so essentially they can work them like a gasoline engine. And because of that, they lose a substantial amount of efficiency, they were 15 percent less energy efficient which is not to say that cost efficient because diesel and natural gas prices are quite different. The Westport Volvo system uses a dual fuel system where they use the diesel to start the ignition and use the natural gas for the -- as the main fuel. But that system's pretty complicated and more expensive. And so far we don't know what the acceptance in the market will be but it's a high cost option. Excuse me.

The one area where these engines have attained significant market share is in buses and in refuse trucks. But that's not been driven through a competitive market but more to local regulations or state requirements that these conversions are occurring. And what we're seeing is they're going to be under pressure from competition from electric and hybrid trucks and buses.

Electric and hybrid trucks, we've seen a whole bunch of them that have been introduced just in the last two or three years. And I talked about the Tesla for the heavy, heavy duty tractor. Truck batteries are generally more expensive per unit of energy storage than car batteries and that's because it's subject to more severe duty cycles. They need very high levels of power demand to be able to supply that on a continuous basis rather than a transient basis and so the cooling systems and the support systems need to be much more durable. We're trying to get a handle on the initial cost but the declines may be similar in percentage terms as to light duty batteries.

Another area that we're having some trouble reconciling what to do with the forecast is that we hear about what the prices ought to be for electric trucks and then when you ask the person what these trucks actually cost, they're about two to three times what we estimated from a cost-based forecast. So reconciling to retail price to a cost-based forecast can lead to some short-term issues in what's being projected for vehicle penetration.

And as a last slide, we are developing these specifications and we expect these to be finalized in terms of the macroeconomics scenarios and electric vehicle cost scenarios. And we hope to develop the draft forecast by early April and continue the forecast refinement over the April to June term and have the forecast essentially complete by the end of summer.

Thank you.

VICE CHAIR SCOTT: Thanks. I had a couple of questions for you as you were going along. On -- back on your Slide 10 here, looking at the light -- light duty electric vehicles. And I'm wondering if you are looking to see what's going on in China and the Chinese ZEV mandate which I think may be driving some of what's taking place on the world stage versus what's going on in the U.S. regulations.

MR. DULEEP: We do monitor the Chinese market and the Japanese market and so on. And what we've found is their costs are indeed somewhat lower than ours. But on the other hand, their safety standards and their durability standards are somewhat different as well. And so the translation may not be one to one.

VICE CHAIR SCOTT: Uh-huh.

MR. DULEEP: The secondary, of course, is that Tesla has probably the largest battery factory of anyone in the world that gives them economies a scale. So looking at Tesla sort of --

VICE CHAIR SCOTT: Uh-huh.

MR. DULEEP: -- takes away some of the differential that we see between China and the U.S. market. So we're trying to focus on what the best might be.

VICE CHAIR SCOTT: Uh-huh.

MR. DULEEP: But then when we look at the future, of course, you know, that tends to be much more speculative because there's so much hype around that it, that (indiscernible) makes sure you walk a tight path between the two extremes.

VICE CHAIR SCOTT: Right. And then you had just on your next -- might have been Slide 12 for the fuel cell electric vehicles. And you did mention that some of this work will need to be done by the Energy Commission. And I just wanted to make sure that our team recalls that we do have our Fuels and Transportation Division which works really closely with the California Air Resources Board to pull together some of the information that you're talking about in terms of how many vehicles are expected, that's a survey that the Air Resources Board does every summer and then on some of the cost, the Energy Commission is doing that work in the -- for a report that's due in December.

So we have -- we do have some good information there that our team can use and would be happy to share with you if it's of interest.

MR. DULEEP: Absolutely, ma'am, and I've been in touch with the Energy Commission's staff on that issue.

VICE CHAIR SCOTT: Oh, great.

MR. DULEEP: I think what I was really talking about is how you predict this transition from a low-volume business to a high-volume business. Because as you know, the automotive business is all about scale.

VICE CHAIR SCOTT: Yep.

MR. DULEEP: And so that prediction I think is -- regardless of losing information an using is a tough one, so that's --

VICE CHAIR SCOTT: Yeah. It's tough to predict.

And then I had -- and it might not be a question for you, but maybe it's a question for the Energy Commission team. You mentioned that CalTrans when you were on your Slide 13 about the medium duty, heavy duty space, CalTrans has a survey with the vehicle miles traveled but not really the miles per gallon that folks are finding in this space. And so I wondered if that was something that we could ask CalTrans to put together for us or to include in their next round of surveys or how we might go about getting some of that information to help to inform us. And you mentioned it's been a couple of decades since it was in the -- in the census where that information so I was just kind of wondering if there were other ways for us to get that information.

MR. DULEEP: I can't speak to the CalTrans forecast because I was trying to get in touch with them on this very issue.

VICE CHAIR SCOTT: Uh-huh.

MR. DULEEP: And apparently, there was a plan to collect the data and I'm somewhat uncertain as to whether the data is collected and not used or never collected. I can't get a straight answer on that. But maybe the Commission can find out.

VICE CHAIR SCOTT: Right.

MR. DULEEP: But I think the other issues that are now private companies that collect data from fleets and sell that kind of data. It'll be beyond our project budget to buy that data but that's something that the Energy Commission could potentially.

VICE CHAIR SCOTT: Uh-huh.

MR. MCBRIDE: Yes. Bob McBride here. We did follow the Cal VIA (phonetic) survey pretty closely for a number of years. There were questions about fuel economy. There was also a concern about the length of the survey and things disappeared. That was not the only thing that disappeared.

VICE CHAIR SCOTT: Uh-huh.

MR. MCBRIDE: But no, we're not getting -- and there are no plans for CalTrans to repeat the VIA survey. I think there are possible other sources. We will continue to look into that. I just notice this -- Mr. Duleep's slides last week and so we'll have to get on it. Either spend money or dig in the books.

VICE CHAIR SCOTT: Uh-huh. Okay. Thanks. Yeah. Thank you very much.

MR. DULEEP: Thank you.

MS. RAITT: Thanks. Next is Mark Palmere from the Energy Commission.

MR. PALMERE: Good afternoon, Commissioners. My name is Mark Palmere and I work on the light duty vehicle forecast within the Transportation Energy Forecasting Unit.

Today I will talk about our base year economic demographic and vehicle data and how they are used in our forecast. These data are used at a very granular level in our model, however today, I will be discussing them more at a higher level. But definitely happy to answer any specific questions that you may have.

The two inputs to our model with the greatest effect on overall light duty vehicle sales are population and income. This is because data have shown that increases in either of those variables will lead to more vehicles being sold. And this is somewhat similar to the chart Nancy Tran shared this morning showing the relationship between income and electricity consumption. We see the same thing at the vehicle level.

Our base year econ and demo data come from the Census Bureau's annual American community survey as well as Moody's and the California Department of Finance.

Some ACS variables released include distribution by county where you can see unsurprisingly that Los Angeles County has about three times as many households as any other county and is followed by San Diego, Orange, and the other counties with large metropolitan areas. Most have similar vehicle to house ratios. Though you can see at the end, San Francisco's is noticeably lower. Regional level distributions such as this are used for our regional distribution EV electric vehicle forecast which is post processed after our statewide forecast is completed.

Next we will take a look at household size and employment as well as income and number of vehicles. Our light duty model categorizes households based on these four characteristics, therefore these numbers do directly affect the forecast.

In 2017, the mean household size was about 2.76 people per household. And slightly over 50 percent of households had either one or two members. Meanwhile, about 70 percent of households had either one or two workers while only about 20 percent had zero.

Median household income was $82,000 or about $20,000 greater than the national average. The statewide average of vehicles per household is about two which is important for ZEV goals because we have found that households with more than one vehicle are much more likely to own a ZEV.

ACS data can get even more detailed as we can also look at traits that have been shown to correspond to PEV adoption. Households living in single family units have been seen to adopt PEVs at a higher rate. And while we don't have a proven correlation, we have noticed the trend, although it could be due to alternative variables. But it could -- but we do think that it could be possibly due to the option of installing home charging and such units.

Over half of all households live in single family detached units meaning that there's a large share of households who could enter the PEV market with the ability to charge at home which we have seen is very important.

Additionally, PEV owners are better educated on average. And the ACS data show that about one-fourth of residents in the state have at least a bachelor's degree or higher. Note that this chart of education includes the entire state population, not just adults meaning that less than high school section can include current -- current students including children who are still studying.

And finally, let's move over to the vehicle section and take a look at the current vehicle market in the state. One trend we've noticed is the shift from light cars towards light trucks. Back in 2013, under 40 percent of new LDV sales were light trucks and that is the category that includes pickups, vans, and sport utility vehicles. Now, due to a number of factors including lower gasoline prices, light trucks make up over half of all new LDV sales in the state.

And if you're looking at this in -- with respect to ZEV sales, there are -- well, there are crossover models and PHEV vans and there are Toxta introduced PEV pickups although that that seems to be distant in the future. We do see the vast majority of PEV sales in the light car category. So the shift towards light trucks is not necessarily a good sign for PEV sales.

But despite that, PEV sales are still going up and this is something we've seen ever since they were introduced back at the beginning of the decade. Their sales have been consistently rising both battery electric and plug-in hybrid. Battery electric sales, and you see these are annual sales 2013 versus 2017. The battery electric sales have increased about threefold while plug-in hybrid sales are a little over double what they were in 2013.

Meanwhile, fuel cell electric vehicles are a bit lower but back, you know, as recently as 2013 they were nonexistent so it -- it's -- they are, you know, beginning starting a bit. And if you notice the comparison between BEVs and PHEVs, back in 2013, there were more PHEVs sold than

BEVs. Now in 2017, BEVs have surpassed PHEVs. And that's something in our prior forecast we had -- we had -- we had been forecasting that BEVs would eventually overtake PHEVs due to the increased number of models and the specific models available.

Lastly, we also look at vehicle miles traveled which is what leads to the fuel demand forecast. Fuel demand is obviously based on the number of miles traveled. And you can see that it has been increasing since the end of the recession of the last decade.

This concludes the transportation portion of the workshop. And although only Ysbrand and myself presented on behalf of our unit as well as Duleep, we do have a full team of transportation forecasters and here is everyone's contact information as well as there area of specialty.

Thank you.

VICE CHAIR SCOTT: Thanks.

MS. RAITT: Thank you, Mark.

So we're going to change the order of the meeting schedule a bit. So next we're going to go to Cary Garcia to have him present on energy efficiency and demand modifiers.

MR. GARCIA: All right. We started easing into the wonkiness, we got deep into the wonkiness, and we'll try to ease out of it now.

All right. So once again, I'm Cary Garcia, lead forecaster for the Demand Analysis Office.

So today sort of got into the overall demand forecast process for this year's IEPR but I didn't really concentrate on the energy demand model so I'm going to touch on that a little bit. There's some other inputs and assumptions that we make there. And so I'll discuss that now.

So this is basic overview of our energy demand model system. So at the top there, you see some of the major inputs, economic and demographic activity. Historical, electricity, and natural gas consumption. And that information feeds into our transportation energy models, each of the sector models that we have as well as self-generation. That information gets summarized there at the bottom in that orange box and that will feed into our peak demand and hourly forecasting models.

But the one piece that I didn't mention is the energy efficiency and demand response assumptions that we incorporate. And so I'll talk about that right now. So really we kind of -- we basically bifurcate, I like using that word, otherwise just splitting into two our energy efficiency savings that we incorporate. It makes me sounds smarter when I say bifurcate. So committed efficiency savings and then we also have additional achievable savings. And the two ways you can really do that bifurcation is by thinking about, you know, is that savings funded and does it have a detailed, you know, implementation plan. Or is it -- is there a mechanism for that to get, you know, integrated and to plan for it but not necessarily everything's really locked down but there's generally a reasonable expectation that you should account for that for planning purposes. So that's a decision we generally make and there's some analysis that goes into that that I'll talk about a little bit later.

And so really the -- what we have to do is we're sort of making this tradeoff between what is our additional achievable energy efficiency and what is committed savings. Some easy examples are now that we have the 2019 Appliance and Building Standards adopted and implemented, those will now be incorporated as committed savings which will be included in our baseline demand forecast. Other information like we're basically going to assume that 2017 is going to carryover for -- to 2018 for the IOU and POU programs and we'll include that as committed savings as well.

The one little wrinkle is that now we have this rolling portfolio cycle from the CPUC. Typically, this would have been -- we would have, you know, EM and EV information and solid savings estimates one to three years out for the -- for energy efficiency. But now we have this ten-year funding cycle and five-year business plans along with annual evaluations of these portfolios. And so we have to do additional analysis to basically understand what we should be including in that committed savings bucket and what should not be and what should possibly be continued to be included in our additional achievable kind of nomenclature there.

So that's something we're working on with the CPUC. We're having some preliminary discussions looking, basically at data requests to the IOUs to understand, you know, what seems reasonable right now, what seems the most, you know, quote, unquote committed. And the other wrinkle there I should probably mention is the fact that some of these programs are now going to be implemented by third-party implementers. So that's kind of a change there. So there's some uncertainty. But we're working with CPUC staff and the IOUs to understand, you know, where to draw the line between committed and what's additional achievable.

So going into the 2019 forecast were also include some new AAEE estimates and so we, as you may know, we have the potential and goals study that's getting kicked off. So we'll get that information for the revised forecast. We won't be able to include that now. We may have some preliminary numbers to look at in the meantime, but the goal is to have that additional achievable energy efficiency from the potential and goals study incorporated into the revised forecast that I mentioned. We would have a workshop on that in December and subsequent DAWG workshops as well.

COMMISSIONER MCALLISTER: So, Cary, just a clarification, I guess.

MR. GARCIA: Uh-huh.

COMMISSIONER MCALLISTER: So how are you tracking our achieved energy efficiency for sort of accounting towards accomplishing our SB 350 doubling goal? You know, it's confusing to a lot of people that once a one forecast, you know, there's this AAEE and then the next forecast part of that, what was AAEE is now in the baseline and we sort of have this kind of rolling cannibalization, it looks like, right? So. But we have to start at, you know, I forget the base year, but for I think 2015 for SB 350 doubling. So is that -- hopefully that calculation is sort of happening alongside the iterations of the forecast each year.

MR. GARCIA: Right. Yeah. We'll definitely account for that, I'd have to look at our efficiency unit perhaps to talk about that in more detail but we do account for that -- that transition going from the same kind of nomenclature, right, what is committed versus what is going to be additional.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: Looks like Nick might have some more to add.

MR. FUGATE: So I was just going to say that, yeah, so we have sort of two considerations here. One is just accounting for these two kind of flavors of efficiency in our demand forecast. And then we have, as Cary mentioned, our SB 350 unit essentially taking on the role of tracking, sort of the entirety of efficiency as it relates to the SB 350 targets. So it's kind of two separate efforts --

COMMISSIONER MCALLISTER: That crosswalk has to be --

MR. FUGATE: -- that are related --

COMMISSIONER MCALLISTER: -- coherent, right? The crosswalk between the two has to be clear what the methodology is and all that, right?

MR. FUGATE: Yeah.

COMMISIONER MCALLISTER: Yeah. Okay.

Okay. Thanks.

MR. GARCIA: Yep. So as I mentioned, we have the potential and goals study coming out but we also include potential and goals from POUs. We have that information now so we'll be including that in the revised forecast. And we're also -- as we kind of talked about, SB 350, we'll include that nonutility programs, things like Prop 39 and such. So those are kind of locked down.

Funding streams, not clear what those impacts are but we have the best estimates that we have to incorporate those in future. And as well as we'll have future, you know, accounting for future ratchets of efficiency standards and so that's always been incorporated into our AAEE estimates as in previous forecasting cycles.

And I should also mention, we are digging into fuel substitution. I know that's kind of a hot topic, fuel substitution, building electrification. So we are doing some -- we want to coordinating a little bit more with the CPUC around SB 1477 and AB 3232. So we've done some preliminary sort of -- how do I say it -- preliminary analysis to kind of look at what are some what if scenarios around that. So let's get -- let's look at what those bookends are, what is an extremely high scenario, what's an extremely low scenario. So we're doing that right now. Not ready for like a prime time, but that's something we can talk about in a DAWG, get some technical experts from the IOUs as well as our other sister agencies to kind of discuss what are reasonable scenarios. Maybe refine the scenarios that we have now and perhaps define some more scenarios in the future for that there.

So moving on from that and kind of how do we apply this to the forecast. So as I mentioned, the committed efficiency savings is typically just included into our baseline forecasts. And as Sudhakar mentioned earlier this morning, AAPV will now be incorporated into that baseline forecast.

But for our managed forecast, what we used as our, you know, our single forecast set and for planning purposes for the ISOs, TBP, transmission planning process as well as the CPUC's IRP process, we generally incorporate the energy efficiency savings plus the additional SB 350 scenario analysis into those AAEE savings to create our managed forecasts that I mentioned will be used or typically used for single other agency's planning purposes.

And a last bit that I should mention is the load modifying demand response. So this is not applied to our managed forecast but imbedded into our baseline forecasts. So we break these up, once again, bifurcate it -- have to use that word again -- to nonevent based and event based. So time of use rates, permanent load shifting would be those nonevent based scenarios. And then the event based like critical peak pricing and peak time rebates. And the two sources of that data are the IOU load impact reports which we should be receiving in April of 2019 and then as well as our rate forecast that Lynn mentioned. She'll give residential TOU impacts and that -- we'll include that into our LMDR estimates.

I should also mention, sometimes it's brought up that we're not incorporating all demand response, but we typically focus on the load modifying part of it, whereas we don't really want to touch the supply side resources. We kind of leave that to the ISO and how their markets operate. So we want to make sure we still incorporate in that forecast, we're not shaving that off when there could be opportunities there. So that's generally the distinction. I hear that comment once in a while, we don't have enough DR in there but I think there are areas where we could incorporate more and perhaps even look at it on an hourly basis, Chris might talk about that later today but generally we think we're doing a good job. But if there are more DR information to incorporate, we're all ears to do that. I know there's new programs and things coming out in the future so we're happy to do that.

Just a few more inputs and assumptions. As we all may know, we do incorporate climate change into our demand forecasts. We do not include climate change into the low scenario but our mid scenario includes a moderate amount of climate change that's our likely scenario that we receive from Scripps Institute. And then we also have a higher demand scenario, a higher climate change impact scenario that's applied to our high demand case. And that's generally just warmer temperatures in comparison to normal right now. And that obviously has energy impacts from heating and cooling.

We also incorporate the transportation electrification information that we receive from our transportation unit. So that's like portal electrification, other medium heavy duty vehicles. One thing to note is given -- typically we used to incorporate high-speed rail but now that has gone quite a bit out into the forecast horizon, kind of beyond our 2029, 2030 period so we'll not be including it in this forecast but as we start getting closer to when we see implementation happening, we'll bring that back in and account for that on the demand side electrification.

And lastly, you may remember from the 2019 -- 2017 IEPR, we incorporated an analysis on the potential impacts from cannabis cultivation. So we're going to revisit that again. I believe last year the really -- it wasn't clear if that was a big enough impact. We're already -- we would already be incorporating some information from that in just our baseline demand forecast. But we're going to revisit that again to see if there's an incremental amount that we should account for. So that's an analysis that we'll have to dig through. But we should know by the revised whether or not we're going to incorporate that directly into the demand forecast this year.

And I'll just --

COMMISSIONER MCALLISTER: Cary, where are you getting your data on the cannabis piece?

MR. GARCIA: I don't know, that was before my time. I came on in the 2018.

Does anybody recall where our data came from? I'll have to crowd source information from them. I think Chris knows.

COMMISISONER MCALLISTER: Hopefully it's not personal experience.

MR. KAVALEK: Chris Kavalek, Energy Assessments Division.

I'd have to go back through our -- the appendix to our report to look at all the data sources, but there's a bunch of studies that have been done on the amount of cannabis consumption when you go from it being illegal to legal in other states. The question, of course, is how well does that apply to California? And there are other scenarios that have been developed. You make assumptions and imputations about the number of customers you might have in the next ten years given the amount of people that consume it now.

It's very preliminary and as we said in the -- in our last forecast report, this is just sort of a very preliminary what if type of outlook. So what we're going to do now, what Cary was alluding was to see how much better the data sources are that we can get for this forecast and if that allows us to put together a forecast and if that forecast is significant substantial enough to where we want to include it in the demand forecast.

COMMISSIONER MCALLISTER: Okay. Okay, it makes sense.

MR. GARCIA: So on the record, it's not personal experience.

COMMISSIONER MCALLISTER: All right. I mean, the sort Zike guys saying that three-quarters or four-fifths of the cultivation is still for the illicit market. And yet the sort of legit folks are going industrial, so maybe that's where most of the energy consumption is. But I don't know. I mean, it seems like things are moving so quickly that we ought to try to identify some good -- some data sources, some formal data sources now that there's a formal part of the economy.

MR. KAVALEK: Yeah, and among the many uncertainties, I'll add the means of production because there's a big difference in energy usage between small scale production on the residential side and large scale farming and industrial type of output.

COMMISSIONER MCALLISTER: Yeah, for sure. Evan Mills at Berkeley Lab has done for the last 20 years or so has done research on this as a, you know, trying to make these estimates. Now that was all prelegalization but it would be probably helpful to get in touch with him.

MR. GARCIA: Okay.

VICE CHAIR SCOTT: Are you looking large loads sort of like the, you know, disappearing and appearing large loads like the bitcoin and some of the other data mining block chain kind of things, right? So I've seen some work on those where there are just these huge loads that are added to the grid and then they're able to be kind of be taken off and then put in different places depending on what's going on. And I don't know whether that's a huge concern in California or not or if there's things like that that we're looking at as well to add to this list.

MR. GARCIA: Yeah. We -- so -- first we did incorporate an incremental adjustment for Silicon Valley Power around their data centers. So that's something that's related there. And so that's probably something we want to keep an eye on as well, particularly in that Bay Area region, potentially even down south in some of those tech, you know, what do you they call it, Silicon Beach, I think. I'm not too sure if they actually get into that.

But if I recall correctly, a lot of the bitcoin, I think there's a lot of heating load that happens, right? So you have to cool those things down. And I want to say, you know, places that are actually very cold from what I understand are actually optimal. I think I want to say anecdotally I heard like Iceland is an idea place because it's so cold so you don't have to do that cooling.

But yeah, it's something we can look at and maybe see perhaps in our next conversation with Silicon Valley Power if they have any sense of any of that is going on. But I imagine it's not so much in California but probably places with very low electricity rates and that are very temperate so you don't have to add on that additional cooling load to keep those things stable.

COMMISSIONER MCALLISTER: Yeah, I'll just pile on. I know that one of the world's experts on data center energy consumption is Jonathan Koomey who is now independent, was at LBL for a long time. And he's actually working on this bitcoin issue to see how big of a deal it really is.

But I think preliminary it's probably overblown in terms of its, you know, growth, its actual energy consumption. But it would be good to check in with him to see what he's found.

MR. GARCIA: And is that analysis specific to California or?

COMMISSIONER MCALLISTER: No, I don't think it is, I don't think it is.

MR. GARCIA: Okay.

COMMISSIONER MCALLISTER: But there's a lot of gray -- there's gray literature making these assertions and so I think he's just trying to give it a little bit of rational analysis.

MR. GARCIA: Okay. That would be good.

Okay. Are there any other -- other questions on that? No? Okay.

Just really going to overview what I mentioned earlier today. So we'll have that -- aiming to have that preliminary workshop in August. A revised workshop in December. In the meantime, we will -- we're planning on some DAWG meetings in July time period so we can dig in to the demand forecast as well as the transportation. Getting more into the wonkiness even further.

And then we'll have the revived workshop with the demand -- demand analysis working group meeting ahead of that as well to kind of share that with all our stakeholders. Once again, get into the wonkiness. And then hopefully we can get that adopted in January of 2020 on our normal time schedule. I know last year we were delayed but we seem pretty confident, we have the schedule laid out so we should have everything wrapped by January for sure.

So I'll leave it at that. I should mention I kind of got into everything high level, so Chris is going to get into more detail on the hourly basis sort of obviously taking our annual forecast and you're digging it down to the hour. So he's going to talk a little bit about that and provide some updates on where we're at on that analysis.

MR. KAVALEC: Thank you, Heather.

Good afternoon, I'm Chris Kavalec from the Energy Assessments Division.

In the last couple of forecasts, we have attempted to provide an hourly load forecast for the three IOU transmission access charge areas that make up that California ISO territory.

Today I'm going to talk about updates that we're going to make for the preliminary forecast for the hourly load model. There will be more updates as we get to the revised forecast, but I'm focusing today on our preliminary forecast.

So a little bit of background. Why are we doing an hourly load forecast? Well, probably the most important reason is that anymore to do a proper peak forecast, you need to account for the time of the peak. In other words, potential peak shifts that happen from one hour of the day to a later hour caused by demand modifiers, particularly PV adoption. So in order to properly characterize peak, you need to know the timing as well as the magnitude so you need an hourly load model.

We also provide monthly peaks for the resource adequacy proceedings from the hourly load model. And because of renewables and flexibility analysis, ramp-ups on a daily basis have become more and more important in resource planning. So obviously with an hourly load model, you can pull out daily ramp-ups of hourly loads.

Just a little bit about the structure, I won't get too technical here. But what we're doing with the hourly load model is we're estimating hourly consumption load ratios based on weather and calendar variables. And when I say load ratio, that means hourly consumption divided by the average hourly consumption throughout the course of a year. And you'll notice that consumption is there in quotes and that's because it's not actually a measure of total consumption. For example, it doesn't include electric vehicles because those are modeled separately in the hourly load model.

So our dependent variable, the variable we're predicting is the load ratio as I described it. And then we take our long-term IEPR forecast which produces annual forecasts of consumption. We take the appropriate annual consumption, we divide that by 8760 to turn it into an average hourly value, multiply it by the predicted load ratios, that gives us predicted consumption in each hour.

We then adjust the hourly consumption by estimates of hourly EV load, climate change impacts, other minor consumption adjustments including residential TOU. And then we -- from that, we subtract off PV generation to give us baseline hourly sales forecast, meaning the amount of load that has to be supplied by the utilities as opposed to total consumption.

And then when we get to the managed forecast, we're subtracting off our estimates of AAEE in an hourly level to give us our managed hourly forecast.

Today I'm going to focus on two of these variables that we're updating for the 2019 preliminary forecast. Hourly climate change and hourly EV loads. Since 2009, we the staff have developed annual additional climate change load impacts for the demand forecast. I say additional here because presumably climate change is already happening and therefore its impacts are imbedded in the historical load.

So we estimate annual additional climate change impacts for consumption and peak. We do this using temperature scenarios from -- brought to us by Research and Development Division in conjunction with the Scripps Institute of Oceanography. So they provide us various scenarios that include daily maximum and daily minimum temperatures under varying assumptions about the severity of climate change.

Now for the -- our forecast update, because we want to incorporate, even these are -- we have annual values, we want to attempt to incorporate that into the hourly load model because we don't want to deliver an hourly load forecast and say well, to pull the peak out of here, you need to then make an adjustment for climate change. We want to actually imbed it in the hourly load model so you can pull out the peak directly without having to make adjustments.

So for the forecast update in 2018, we distributed the annual consumption impacts from climate change to the various hours and the coldest and the warmest month based on estimated cooling and heating loads in those months. So basically we're imputing hourly heating and cooling by comparing the load shapes in a given cold or hot month with load shape in April where you don't have much cooling or heating.

So we're imputing the hourly heating and cooling, we're using that to distribute the climate change consumption load impacts over the course of the year with the constraint that the -- the impact peak has to match what we've estimated for the annual peak impact from our previous -- our annual analysis.

As I mentioned -- well, going back a second, as I mentioned before at a previous workshop, this is a crude way of doing it and we want to try and develop a more refined method going forward. As I said, the temperature scenarios that we get now for climate change only include a daily maximum and minimum. For the forecast this year, Scripps is currently working on developing hourly temperature scenarios imputed from the daily maximum and minimum temperatures.

There are various ways I've seen in the literature of doing this, taking an hourly maximum and minimum and fitting it to hourly temperatures, an hourly temperature profile using the historical data. And I'm not completely clear on which -- they're developing a new method and they're going to provide a white paper that we can post and they're going to attempt to incorporate this into a professional journal article.

But anyway, they're working on developing an hourly temperature scenario so that we can fit in, do a more refined job of incorporating climate change within the hourly load model.

Okay. Hourly EV loads. For the last two forecasts, we used hourly EV profiles developed by Lawrence Berkeley. And they used national household travel survey data for those surveyed in California and sort of imputed a charging pattern for electric vehicles based on travel behavior of California households.

Well, for going forward, as part of our larger load shape effort that we have undertaken the last couple of years, ADM has developed new profiles based on actual vehicle charging data from ChargePoint. And ChargePoint has a lot of information available and stored like vehicle type, charging time, charging duration, and so on. It has a lot of information. So they're -- so we're actually using charging data directly rather than imputing charging behavior based on travel behavior.

And they also got data from the joint IOU electric vehicle load research report, metered residential charging profiles. And those -- those are drivers that are under residential TOU rates. So what ADM did was to take the general vehicle charging data and estimate an elasticity, a price elasticity for hourly rates based on the difference between charging behavior in the general population coming from ChargePoint and charging behavior from those in the joint IOU research report that were metered and were faced with residential TOU rates. So that's where our price elasticity comes from.

Now as I mentioned, this electric vehicle loads come from a larger effort to reestimate or updated all of our end use load shapes. For example in the residential sector, we have 24 end uses, lighting, refrigeration, cooling, heating, et cetera. And those hadn't -- those load shapes had not been updated since the '90s, although we did do a minor update in the 2000s.

So all of these load shapes have been updated and are being delivered to us in the form of a new hourly electricity load model, or HELM, that we have traditionally used to estimate annual peaks. And we're calling this HELM 2.0. They're putting the finishing touches on the model so I don't have anything to show you yet today, unfortunately. But they're working -- putting the finishing touches on the model and hopefully in the next week or so we will be delivered a working version of HELM 2.0. And then we will put the model through its paces, test it, see how well it performs.

So the question becomes, well, we have an econometric hourly model that I've been talking about, now we have -- we also have this updated hourly electricity load model, a bottoms up model as opposed to a top down model like the econometric model. So the question is, what do we use going forward for our hourly load forecast? Ideally, you would want to use the HELM 2.0 output. Because not only do you get, you know, hourly loads, but you can break those hourly loads down to residential, commercial, industrial, even down to the end use level. So it would provide a lot more information.

And if -- if we went that route, then the -- our econometric hourly load model methodology would be used to look at maybe more refined geographies, more refined than what is covered within the HELM model. So.

COMMISSIONER MCALLISTER: Chris, do you have an idea of what -- how you will gauge whether the two models are roughly in sync or not? Like, you're going to get different results and you've got to figure out whether it makes sense, right?

MR. KAVALEC: Yeah. Yes. That's -- that's -- that's the question. What constitutes a set of reasonable outputs for the new HELM model relative to history? That's something we're going to have to figure out. But we have found in the past -- years ago we attempted to develop a 8760 set of loads from the previous version of HELM. And while the HELM methodology is good at predicting annual peaks, we found, it's not always so good at predicting an 8760.

The reason for that is that when you calibrate to historical data, you'll sometimes end up having to torture the individual end use load shape so much that they become unrecognizable. Hopefully that won't happen this time. ADM who we've been impressed with how meticulous they've been in putting this together and they're aware of this problem. But if it turns out that we're not happy with the 8760, it just doesn't perform like we had hoped, then probably the solution would be we wouldn't continue with our econometric hourly load model and calibrate the results to the HELM annual output rather than use the 8760 from the hourly load -- or the HELM model.

COMMISSIONER MCALLISTER: Okay. That makes sense.

So in terms of the vetting like if we're not -- how would we know if we're not happy with the HELM 2.0 output? I mean, is that working with CAISO and the PUC and kind of going back and forth about the hourlies and monthlies or what?

MR. KAVALEC: Yeah, it's just -- it's just a matter of deciding what would be the proper timeframe to look at the historical data. How close it should be. How it compares to historical averages. And how it performs relative to the hourly load model which we're fairly happy with now in terms of an 8760.

COMMISSIONER MCALLISTER: Okay. Thank you.

MR. KAVALEC: So if it's way off compared to the hourly load model, that's not good.

COMMISSIONER MCALLISTER: Okay. All right. Well, yeah, that'll be interesting to see how it goes.

MR. KAVALEC: We'll keep you posted.

COMMISSIONER MCALLISTER: Please do. Thanks.

MR. KAVALEC: I guess that was all I had.

COMMISSIONER MCALLISTER: Well I got my question.

MR. KAVALEC: Okay. Thank you.

COMMISSIONER MCALLISTER: Thanks, Chris.

MR. KAVALEC: And thank you for hanging with us all day.

MS. RAITT: All right. Thanks.

So it looks like we're on to public comment. I don't have any blue cards. I don't know if anybody --

VICE CHAIR SCOTT: Just double check. Do we have any comment in the room? Okay. We're not -- for those on the WebEx, we're not seeing anybody raise their hands or run up to the podium.

Let's check, did we have any on the -- we're not seeing any hand raisers on WebEx either.

MS. RAITT: Use your raise -- raise your hand function if you do have one.

VICE CHAIR SCOTT: Give you a second to -- all right. Back to Heather.

MS. RAITT: Okay. So written comments are due March 18th and all the information's on the notice and also listed here on the slide for how to submit comments.

VICE CHAIR SCOTT: All right. Thank you so much to our staff for putting together an excellent workshop for us today, we really appreciate it.

And to folks who have data or information or insights on this that they'd like to share with us, please do be sure to get your comments to us on or before March 18th. We'll be looking forward to hearing from you.

Thank you very much, everybody, see you at the next one. We're adjourned.

(Thereupon, the Hearing was adjourned at 2:38 p.m.)

--oOo--

REPORTER'S CERTIFICATE

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

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 6th day of May, 2019.

Myra Severtson
Certified Transcriber
AAERT No. CET**D-852