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CALIFORNIA ENERGY COMMISSION

COMMISSIONER WORKSHOP

In the Matter of:	)	Docket No. 19-IEPR-08
	)	
2019 Integrated Energy Policy	)	RE: Revised Natural Gas
Report (2019 IEPR)	)	Price Forecast and Draft
	)	Outlook/Electricity
______________________________	)	Modeling Results

CALIFORNIA ENERGY COMMISSION (CEC)

WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM, FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, OCTOBER 30, 2019

10:00 A.M.

Reported by:

Peter Petty

APPEARANCES

COMMISSIONERS AND ADVISORS

J. Andrew McAllister, Commissioner, California Energy Commission

Linda Barrera, Adviser to Vice Chair and Lead IEPR Commissioner Scott

CALIFORNIA ENERGY COMISSION STAFF

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Jennifer Campagna, Supervisor, Natural Gas Unit, Energy Assessments Division

Anthony Dixon, Natural Gas Unit, Energy Assessments Division

Angela Tanghetti, Supply Analysis Office

Peter Puglia Natural Gas Unit, Energy Assessments Division

Lana Wong, Southern California Energy Reliability

Hazel Aragon, Supply Analysis Office

PUBLIC COMMENT

Tim Carmichael, Southern California Gas Company

Sam Wade (via WebEx written comment)

AGENDA

P R O C E E D I N G S

10:03 A.M.

SACRAMENTO, CALIFORNIA

THURSDAY, OCTOBER 30, 2019

MS. RAITT: Okay. I'll go ahead and get started with some housekeeping items.

Good morning. Welcome to today's IEPR Commissioner Workshop on the Revised Natural Gas Price Forecast and the Draft Natural Gas Outlook/Electricity Results -- it should be Modeling and Results. I'm Heather Raitt. I'm the Assistant Executive Director for Policy Development and the Manager for the IEPR.

Quickly, housekeeping items.

If there's an emergency, please follow Staff out the doors to Roosevelt Park, which is diagonal to the building.

And, also, please note that our workshop today is being broadcast over our WebEx conferencing system and there will be an audio recording posted from the workshop in about a month. We'll also have a written transcript that will also be posted, probably in about a month as well.

We're going to have an opportunity for

written comments -- excuse me -- verbal comments today at the end of the workshop. It will be three minutes per person.

So, folks in the room, you can fill out a blue card and give it to the Public Adviser or myself and we'll make sure you have your opportunity to comment.

And then folks on WebEx, just go ahead and use the raise-your-hand feature to tell us that you are interested in making comments. And you can also use that feature if you change your mind and decide not to make comments.

The notice for this workshop says that written comments are due on November 11th. We're going to extend that because the report today will have the results that Staff will present on but we don't have the actual report posted yet. So we're going to go ahead and extend that comment date to November 27th, and we'll put a notice out to that effect, and that should allow for plenty of time to review the report and provide comments.

And that's all I have.

So if Commissioners would like to make opening remarks?

Thank you.

COMMISSIONER MCALLISTER: Okay. Thanks Heather.

So I just want to welcome everybody. This is, you know, it's a little bit -- among the folks who know about natural gas, you know this is a big deal, and I think all of you know how big a deal it is. There's a lot going on in California right now across the Board with energy.

Certainly, our hearts go out to all the folks affected by the wildfires. And that, I think, just gives immediacy to the conversation we're having, even though, you know, it tends to be among the experts, this has real, you know, implications, how we frame and perform our planning around natural gas, increasingly as related to electricity. It's always been but even more so today. And I think there are just many, many issues that are intertwining every more between the electricity and natural gas sectors.

And so all of this just highlights how important it is to have a fully formed analysis and assessment. And I think I get a lot of comfort from the fact that we have some incredible experts on staff and on our team at the Energy Commission to really do scenario analysis and look at the natural gas market, sort of in the light of day and with kind of cold, hard analysis and then, also, with the subtlety and the expertise that's needed to anticipate scenarios and look at possibilities going forward.

You know, we're trying to think about what the range of possibilities is, actually, for the future of natural gas. And we're doing some R&D work on that front. We're working across the agencies, PUC, and with the ISO, and trying to sort of figure out what the range of possibilities actually are -- actually is.

And so looking forward to all the presentations here. I wanted to thank Siva and his team. He was on his -- I guess he's probably in India by now on some well-deserved vacation. Alicia, his Deputy, is holding down the fort ably. And then our team, Melissa and Angela Tanghetti and all the presenters that we'll here today from the Commission staff. And I'm certainly looking forward to any comment that we have from folks in the room and on the web, and written comments later on that will be due on the 27th, as Heather said.

Happy to be joined on the dais by Linda Barrera, Adviser to Commissioner Scott.

So, Linda, you want to say some words?

MS. BARRERA: Thank you. Good morning. Commissioner Scott is very sorry that she couldn't make it today. She'll, of course, work closely with Commissioner McAllister and Staff on this important Natural Gas Forecast and Balance Assessment. And she will also closely review any comments the Commission may receive on this workshop and on this topic.

And I personally want to thank Staff for all the great work and effort on this part of our IEPR. And I'm looking forward to listening to your presentations.

Thank you.

MS. RAITT: Great. So our first presenter is Jennifer Campagna from the Energy Commission.

MS. CAMPAGNA: Good morning. My name is Jennifer Campagna. I am the Supervisor of the Natural Gas Unit in the Energy Assessments

Division. Today, I will be presenting an overview of the Draft Natural Gas Market Trends and Outlook Report. As Heather mentioned, it will be posted soon for public review and comment.

So the Natural Gas Outlook Report is a biennial report. It's produced every two years. It is a technical supporting document for the IEPR. This report contains a little bit more detail than the actual IEPR chapter that will be published this year. But the IEPR chapter, which is titled Natural Gas Assessment, is chapter nine. It will contain policy recommendations. That is the key difference between the two.

Here we have -- sorry -- here we have just a brief look at the report structure. The main component of the natural gas price -- of the Natural Gas Market Trends and Outlook Report is the natural gas price outlook. Staff uses the NAMGas Model to produce natural gas price projections on a nationwide level, and for California. This year the model will project out to 2030. Anthony Dixon will provide detailed results on these natural gas price projections in the upcoming presentation.

Since the April 22nd Natural Gas IEPR Workshop where we presented the preliminary results, Anthony has made updates to the modeling inputs and has incorporated the draft production cost modeling results from PLEXOS. And these changes will be reflected in the results that appear in the natural gas price outlook.

We also have a chapter on Natural Gas Supply and Reduction. No real surprises here, a lot of the same trends that we saw in the 2017 IEPR. On a U.S.-wide level, production is still increasing, largely due to shale production. The U.S. did become a net exporter of natural gas in 2017. In California, we're still seeing a reliance, mostly on out-of-state natural gas sources, approximately 90 percent still.

One notable event is that because of passage of Assembly Bill 2195, the Air Resources Board will start tracking out-of-state GHG emissions from natural gas that is being imported to California. And they'll be publishing that annually.

Just continuing on natural gas supply and production, the report does provide a brief overview on Canada and Mexico. In Canada, production is still growing at a rate of about two-and-a-half percent per year. And natural gas serves about one-third of that country's energy requirements.

Mexico, we're seeing pretty rapid growth in demand for natural gas. Since early July 2019, Mexico's president has been renegotiating contracts with Canadian and U.S. companies for seven natural gas pipeline systems that were in various stages of construction. In late August 2019, Mexico's president announced a deal that will allow this construction to move forward. These natural gas deliveries will allow quite a bit of natural gas to flow into Mexico to meet that demand.

We have a chapter on Natural Gas Demand, again, from the U.S. perspective, and California. In the United States, since 2005, most of the growth has been in power generation, industrial sector, and liquified natural gas exports. The growth has been pretty flat for residential and commercial. Transportation is growing but it's still a very small part of consumption. This increase in demand is largely due to a shift away from coal generation and continued low natural gas prices.

In California, we see declining consumption in the residential sector that will continue, a slight decline in power generation going forward. We do some growth for renewable natural gas for transportation and we expect this to continue.

There’s the chapter on Infrastructure and Reliability. In the United States -- I’m sorry, I just lost my notes here. Okay. In the United States, we’re seeing record levels of associated gas production in the Permian Basin, so we expect production from there to double by 2025. There’s new pipelines coming online that will help move this gas to the Texas Coast for liquified natural gas export.

In California, we do not expect to see any new pipelines or storage facilities to be built, largely due to our policies emphasizing electrification and decarbonization. A main issue that we need to keep track of is the aging infrastructure and the cost to maintain that infrastructure as we move towards electrification. And if renewable natural gas and/or hydrogen may need to use this infrastructure, that's going to become a critical issue.

We have a section on SoCalGas and their infrastructure, and PG&E. Southern California Gas pipeline maintenance issues in Aliso Canyon, we touch on that in the report but we refer readers to chapter six of the IEPR because those issues are covered in detail there.

PG&E, we discuss, briefly, their storage strategy that's part of the rate case right now at the CPUC. They are looking to sell two other storage facilities, Pleasant Creek and Los Medanos. And that plan was approved recently by the PUC but PG&E does have to submit a Sales Plan and a Reliability Study specifically for Los Medanos before final approval.

With that, I conclude my presentation. I just will note again that we do have a Natural Gas chapter in the IEPR that will summarize the issues in this report and will make policy recommendations.

The Appendix A of our Outlook Report gives detailed description of the production cost methodologies from the PLEXOS Model. And Angela Tanghetti will provide a detailed presentation on the PLEXOS modeling results later this morning.

And Appendix A of the IEPR has a section on Assembly Bill 1257, the Natural Gas Act and those requirements. And Peter Puglia will provide a presentation on that later this morning.

Thank you. My contact information is available if you have any questions or comments. Thank you very much.

COMMISSIONER MCALLISTER: Thanks Jennifer.

MS. CAMPAGNA: Okay. Thank you.

MS. RAITT: Thanks Jennifer.

So the next speaker is Anthony Dixon from the Energy Commission.

MR. DIXON: Good morning. So I am Anthony Dixon of the Energy Assessments Division. I am here to present our revised results for the North American Market Gas Trade Model, or NAMGas.

The first few slides, we're going to skip through because they were presented and haven't changed since the last workshop, but I wanted to keep them here for reference so we would have them if anybody wanted to look and didn't have to go back and look.

So we're going to skip to slide 14. And right there. There we go. This is just kind of an overview of the changes that we made since the last modeling runs.

First of all, which was mentioned just previously and we're kind of going over again, we updated all the demand inputs. That means we took the production cost modeling inputs, their draft inputs, put them in for the power generation sector in the WECC.

We updated the California Energy Demand Forecast into our model, so those are all in there.

We also did some historical calibration. We back cast a couple years in our model. And since we were a little over halfway through this year, I was able to get some data for this year and combine it with the futures' prices to kind of give us a gage of what 2019 prices would look like.

We also, EIA released a new revision to their proved supplies, which is about five percent higher than they were last year. So combining that with some historical calibrations, prices are much lower. You know, supplies are higher, prices are lower.

And we also did some research on the price elasticities. And between that, and some model testing and things like that, we redid the elasticity throughout the model. The key on these elasticities, they are only for the sectors outside of California and, also, non-power gen in the WECC. Those, since other models give us those results, they account for elasticity as we turn those elasticities off in our model. So whatever they give us for demand is exactly what our model puts out.

So onto some results.

So as we can see here, on the Henry Hub price, Henry Hub is the main market price across the country, even North America, for natural gas prices. It's the biggest index. The black line is EIA's forecast from their 2019 release using 2017 data, so it's a couple years old on their data, so prices have declined since then.

As you can see, especially in 2019, we have, really, a drop off in prices. And that has a lot to do with huge production of associated gas in Western Texas, Canada, the Bakken shale. These people are producing, actually going for oil, for natural gas liquids. And the natural gas is just a byproduct and so they're just trying to get it off in the market. Waha Texas spent most of last year, and even part of this year, in negative territory prices because they couldn't get all the gas that they're producing, the associated gas produced, onto the market.

So as we can see, between our cases, we have a price varying between 225 in our high-demand/low-price case and about 430 in our low-demand/high price cases. We're lower than, like I said, the AEO, but that's because they're using a little bit older data. They haven't updated. Next year, you know, by January, they'll have a new one, so I'll be able to look at their newest one to see what is going on and compare our prices.

So demand, this is for United States as a whole, it's pretty flat overall. It's a little bit of an increase, about one percent per year. This is mainly driven by the switchover in power generation, you know, exports in Mexico, and our LNG exports.

The exports to Mexico in our model runs was kind of limited because there was a change.

The current president first was going to shy away from natural gas. And then, of course, in August, and when I'm in the middle of my runs, he decides that, oh, now we're going to go ahead and open up all this gas.

So the next times we do some runs here, we'll have the new pipelines opened back up and that will actually increase a lot because there is -- right now, to Mexico, we're averaging a little over five BCF a day of gas in exports and that's expected to increase substantially, especially if these seven projects all go through and get built in the next few years.

And for the power generation sector, this is driven by the switching from -- because the low price of gas and we're switching from coal to natural gas. One thing this doesn't account for is the new policy of how there are now 11 more states that are pushing for 100 percent renewables. That is not included in this modeling run but it will be put in for the next modeling runs that we do. I'm sure this will probably help flatten this or keep it at least level, if not, hopefully, declined a little bit. But at least you won't see a huge uptick in power gen needs.

There's some research in doing this because part of the power gen increase is not just switching to coal but also the higher demand because we're getting hotter summers and colder winters. We're getting more extreme temperatures so you need more gas for heating, for cooling, for those things. So you have two things that are adding to this demand that need to be kind of fleshed out and looked at.

In production, it's steadily climbing. We have more gas than we know what to do with. So any increase in demand, exports, LNG, there is actually plenty of gas to cover for that. Price is -- another reason for keeping prices, our prices, low. It's just right now with the current rules and everything, we just have a lot of natural gas that we can get at a low price. And as we keep drilling and working, they're getting better at it, it's getting cheaper, and just a lot.

Every, like I said, every proved -- you know, we're drilling and taking a lot of gas out every year. The proved reserves still increase. Our potential reserves still increase every single year. We will be getting, hopefully in the next month or two, the newest Colorado School of Minds, their newest estimates on potential resources.

So now a little more specific into California for our prices. Kind of just as a note, to remind again, that our model does not produce any demands for California. We just take whatever demand offices forecast, we use those, put in our model, turn elasticities off, and just see what prices will do from what they give us.

So one thing we do is, after their final get adopted, I'll put those numbers back in and rerun the model and see if there's any big major changes, and that goes into our IEPR update to see if there's -- because a difference in modeling timelines. So we like to see if their newest forecast changes our model at all.

So as we can see, this is the three major hubs. You have Henry Hub, which is the major North America hub. Topock and Malin are good proxies for California. They're the major input areas for where gas travels into the state. The biggest thing from this that we're seeing is for the first time, well, not first time but we're seeing, on average, that eventually Malin and Topock will both average lower than Henry Hub. And this has to do with all the associated gas being produced in the Waha Texas Basin, Montana, and even up to Canada. They're just producing so much gas at such a low rate and we're one of their main customers. So our hub, our main hub prices coming into the state, will be very low-priced gas.

What goes on to the Citygate and into the state is a different situation because there's a lot more things other than just the commodity price that goes into that final price that a customer would pay, some of it political, some of it policy. All things drive those prices which are very difficult to model.

So kind of some -- the conclusions and review.

So we have our demand for the U.S. growing about 1.14 percent from 2018 to 2030. Our prices for the Henry Hub only reach about $3.43 by 2030, and even out further, they don't get much higher than $4.00, $4.50 in price. Once again, this could very easily change depending on policies, new technology, anything like that can really change these prices. But as we have it right now, high production of associated gas is pushing down prices. We have high proved reserves, high potential reserves, and the efficiency in producing these things is getting better and better, so it's more gas, cheaper to produce.

So some things that we're going to look out for into the future in our modeling is finish developing a monthly model and I'll go over why that's really important, but address the 11 states that now have 100 percent renewable requirements coming up, better incorporate this international developments with the LNG market exploding, with the changes to Mexico market, continue monitoring all the market things to keep our -- you know, update the assumptions.

And then monthly model, why it's such an important thing that we've been working on and really want to get it right is it can really flesh out a lot of things that an annual model cannot. I know last workshop, we talked about the building decarb and how it would affect prices. Unfortunately, in the annual model, it didn't show any difference. It really didn't pick up anything. I have a feeling, though, on a monthly model, when you start seasonality and all these little different changes in a month, you will see a difference which we don't see right now.

The monthly model will also allow us to address things like storage. I can kind of put a price on what happens if we get rid of Aliso Canyon, what will happen to prices locally at the citygates?

We can also do things like weather events. What happens if another polar vortex hits the Northeast? What will happen to our prices? We can do things like better monitor the Southern California issues by shutting off a pipeline for a month or a week or two months, instead of having to shut it off for the whole year. So we'll really be able to flesh those out and look at those types of things.

And a couple other questions that came up at the last workshop was about the associated gas production and flaring and how they had record flaring in Texas. So Texas does have a standard. The problem is they had 27,000 requests to keep flaring beyond what they're allowed to and every single request was granted. So, basically, they don't have any kind of policy if every single request to keep flaring and venting more than they're allowed to is approved. A lot of the pipelines don't like this because they want that gas in their pipelines so they can sell it. So there's kind of a fight there in Texas over that.

A couple other questions was there was some confusion about our Small M Model last time. Our Small M Model is just a very basic regression model that produces a starting point for the NAMGas model. We can't flesh out any state-by-state things, any coal retirements. There was a question about coal and heat rates and the little Small M Model really doesn't account for those things, it's just kind of a starting point where we think things are kind of going. And then once they get into the NAMGas model, which is the bigger model, it really takes effect of all the demands and price elasticities and supply and really, then, we can see where effects happen.

And for that, that kind of concludes. If you have any questions, my contact information is here. And please, also, if there's any questions about any of the prices, that includes the burner tip prices, any of those kind of prices, please point them towards me.

Thank you.

COMMISSIONER MCALLISTER: Great. Thanks Anthony.

I guess just to point out, I mean, you've done a good job, I think, of drawing a boundary around this analysis and sort of pointing out what it is. And I would just point out, you know, we have a bunch of other complementary work going on at the Energy Commission --

MR. DIXON: Um-hmm.

COMMISSIONER MCALLISTER: -- and across the agencies looking at more kind of, you know, tilting towards retail. I mean, this is sort of the basis of the wholesale level but a lot of elements that kind of are not covered here go into that, like, you know, what the natural gas marketplace is going to look like over the next 15, 20, 30 years.

MR. DIXON: Exactly.

COMMISSIONER MCALLISTER: So I would encourage folks to kind of also pay attention to those discussions in terms of, you know, what the full implications of ongoing decline in natural gas consumption --

MR. DIXON: Yeah. And we work --

COMMISSIONER MCALLISTER: -- in California --

MR. DIXON: -- closely with them --

COMMISSIONER MCALLISTER: -- actually is.

MR. DIXON: -- to make sure we --

COMMISSIONER MCALLISTER: Yeah.

MR. DIXON: -- keep everything together.

COMMISSIONER MCALLISTER: Yeah. Because, you know, obviously, we're a recipient of a national and global market --

MR. DIXON: Um-hmm.

COMMISSIONER MCALLISTER: -- and those signals. But there are a lot of other signals that are sort of unique to the west and unique to California and we need to keep paying attention to those.

MR. DIXON: Exactly.

COMMISSIONER MCALLISTER: And certainly, you're not -- without the monthly model, you're really not capturing any of the volatility that we're seeing in the marketplace locally in California?

MR. DIXON: No. And that's why we really

want to push that and get that going.

COMMISSIONER MCALLISTER: Yeah. Yeah. That will be helpful. Okay. Thanks a lot.

MR. DIXON: Thank you.

COMMISSIONER MCALLISTER: Okay. Great. Thanks Anthony.

MS. RAITT: Thanks Anthony.

Next is Angela Tanghetti from the Energy Commission.

MS. TANGHETTI: Good morning. Good morning. I'm Angela Tanghetti and I'm with the Supply Analysis Office. And I'm here to describe our support of the NAMGas modeling assumptions for WECC-wide natural gas use for electric generation.

If you haven't already looked at this presentation, I'm letting you know that I mainly speak in numbers, so my presentation includes a fair amount of tables and charts.

I want to start by saying this draft naming convention for production cost modeling results I'm presenting this morning may be a little bit confusing. And I decided to use the word draft since a draft label indicates these production cost model results are based on a combination of the 2019 IEPR Preliminary Demand Forecast and the revised NAMGas price projections Anthony just presented.

So at this time, our draft production cost model results are based on some preliminary and some revised assumptions. Our Production Cost Modeling Team will develop a final data set once the 2019 CED is adopted in early 2020.

As you can see, other assumptions are unchanged from those we presented at the preliminary Natural Gas Price Forecast and Outlook Staff Workshop on April 22nd of this year. The California demand and the WECC-wide burner tip natural gas price projections are the only key driver updates since our April 22nd projections. So later in this presentation, I'll share comparisons of our selected production cost model metrics for not only the draft mid, low and high IEPR common cases, but also comparisons to the results presented during the April 22nd staff workshop. And this may help you understand some of the key drivers that impact these simulations results.

So here's a simple scorecard for some of the key assumptions that are the basis for our

IEPR common cases. Since the CED 2019 preliminary projections did not include updated AAEE projections, DAO staff, that is our Demand Analysis Office staff, advised us to use the [2018] IEPR Update projections and account for the component of AAEE that is now included in the 2019 preliminary CED.

So, for example, the year 2019 projected AAEE in this forecast is zero, while subsequent years, AAEE projections are discounted from the 2018 IEPR Update since they're now included as part of the preliminary demand forecast.

So the key takeaway from this slide is the difference in California demand projections. The 2019 CED preliminary projections are about five percent lower than the 2018 IEPR Update. Recall, the 2018 IEPR Update are the basis for the production cost model results presented at the April 22nd workshop, while the draft results I'll be presenting here this morning are based on the 2019 CED which, again, are five percent lower.

So just a spoiler alert. With demand forecasts being lower, that means there's going to be lower projections of natural gas use for electric generation and greenhouse gas emissions, but I'm still going to talk here.

So the OTC Compliance Plans and CAISO retired and mothballed list, posted January 10th of this year, is still unchanged from our April 22nd assumptions. And these OTC Compliance Plans and retirements are identical to all of our common cases, the cases presented today and the cases we also presented in April.

Again, these WECC-wide retirement assumptions are unchanged from our April 22nd assumptions. These retirement assumptions do not include the recently proposed California OTC compliance date extensions that you may have all heard about, or any recent Pacific Corps IRP announcements of additional coal plant retirements, or other recent trade process announcements that have recently been posted.

One thing to recall from this slide is Alberta is part of the WECC. And about a third of these coal retirements are located in the Alberta Electric System Operator portion of the WECC. According to their IRP, Alberta announced these coal retirements will be replaced by a combination of gas and renewables, not on a one-for-one basis but they've outlined that they will replace with some gas and renewables as well. So again, it's a significant amount of retirements over the forecast period.

Let's see. Additions are from our subscription database because, again, we have to look at the entire WECC region. So we look through subscription databases to see new and planned generation. We look at Trade Press. We look at the WECC Anchor Data Set. And sometimes these subscriptions, Trade Press or IRPs, are somewhat generic in nature in term, over the forecast period. So again, we do have to add some renewable additions for RPS requirements, both within California and throughout the WECC. But we do lean on our utility IRP filings that have come in, in 2018 and early 2019, to populate the additions in our data set.

Okay, for the sake of time, I only included, in the body of this presentation, the CEC's Statewide Mid Demand RPS Portfolio. So what this gives you is an idea of timing for the existing and projected in-state and out-of-state renewables needed to meet the California RPS. The amount of projected RPS resources for the high and low demand case are, of course, higher and lower than the amounts shown here for our mid demand case and are provided in the backup materials at the end of this presentation since some of these RPS portfolio assumptions are key to some of the greenhouse gas emission projections I'll show you later.

For example, the amount of out-of-state wind, which you can see under the wind category for out of state, to meet the California RPS in the high demand case, we included about 5,000 megawatts more than that in the high demand case by 2030 as compared to this mid demand case. Again, these RPS portfolios for the high and the low demand case can be found at the back of this presentation.

So again, what this shows is by 2030 about 48,000 megawatts of renewables are needed, both in state and out of state, to meet the California RPS.

I think this table is interesting, just to give stakeholders and policymakers some perspective on WECC-wide RPS energy targets for the mid demand case. Some of our western neighbors have recently announced more ambitious renewable and greenhouse gas emission targets that are not yet reflected in these projections. But we're compiling those data and we'll reflect those regulations for regions outside California in our future modeling efforts. As you can see, I've highlighted the California row here in perspective to the total generation required by RPS targets in various other states within the WECC. So California, again, is a significant portion. But again, these are from a WECC-wide perspective, the RPS targets that we're meeting WECC-wide.

As Anthony said earlier in his presentation, decreasing demand for natural gas and electricity in California impacts natural gas prices. These natural gas price burner tip price projections, they show less volatility in the cases in the early part of the forecast period and not such a steep increase as in the low demand case as was found in our April 22nd burner tip prices.

So again, you can see, the burner tip prices are relatively consistent as far as the mid, low and high cases. Previously, the burner tip prices in the low demand case were up to the

$7.00 range, which caused some coal switching, gas and coal switching strategies, are based on pricing in the production cost model. But again, these projections are more stable and cause less extreme variation in the cases.

The coal burner tip price projections are developed using data from the 2019 EIA Annual Energy Outlook, also called the AEO, which you may have heard it referred as that. There are six scenarios the AEO produces and all these cases project little to no variability in coal prices. So we tried to find some projections of more variability in the coal price. But out of all six of those scenarios there was basically no volatility in projections of burner tip coal prices.

So now this chart shows the projections of natural gas demand for electric generation for the three IEPR common cases and the mid demand projections from the April 22nd simulation results. These results are used as input to the NAMGas Model. As you can see, the impact of lower California demand and just slightly higher long-term California burner tip natural gas prices cause a decrease from our previous simulation results. The solid lines are all these current cases, what I'm calling the draft cases. And the dotted green line is just the mid case from our previous simulation. So you can see the impact of the demand projections and different burner tip prices on the natural gas use for electric generation. So again, lower demand, basically, lower gas use.

From a WECC-wide perspective, which does include California, this chart shows similar trajectories for all three common cases. The WECC-wide mid demand case is slightly lower than the April 22nd projections, again, for similar reasons as for the California-only case. Lower California demand projections and slightly higher long-term burner tip natural gas price projections are the key drivers of simulation results. These WECC-wide results are also used as inputs to the NAMGas Model. So again, the solid lines are our current draft results and the dotted line is from the previous forecast.

A visual I like, maybe not my best choice for the color pallet, this graphic provides WECC-wide projections of renewable generation which are shown in the solid bars. So, again, the solid bars are the renewable generation for the three common cases. And they're increasing over the forecast period, in contrast to the WECC-wide coal generation projections by case. And the coal generation is just simply shown as the single lines there. So the renewable generation is in the bars and the coal generation is in the lines. And coal generation is declining over the forecast period, while in all of our common cases the renewable generation is increasing over the forecast period.

Okay, these are not --

COMMISSIONER MCALLISTER: Angela, can I ask a question

MS. TANGHETTI: Yes.

COMMISSIONER MCALLISTER: -- ask a question --

MS. TANGHETTI: Yes.

COMMISSIONER MCALLISTER: -- just about -- just to be clear, you're talking about RPS-eligible renewables here?

MS. TANGHETTI: Correct.

COMMISSIONER MCALLISTER: Okay.

MS. TANGHETTI: RPS-eligible --

COMMISSIONER MCALLISTER: Yeah.

MS. TANGHETTI: RPS renewables --

COMMISSIONER MCALLISTER: Okay.

MS. TANGHETTI: -- from a WECC-wide perspective.

COMMISSIONER MCALLISTER: Okay. Great. At some point, we're going to have to sort of go along symbiotically with the SB 100 definition--

MS. TANGHETTI: Exactly.

COMMISSIONER MCALLISTER: Workshops will have this conversation and figure out how to morph our definitions but because you know, without losing continuity in the analysis here.

MS. TANGHETTI: Right. So WECC-wide renewables, as well as carbon free resources will need to be defined through the lens of SB100

COMMISSIONER MCALLISTER: Yeah, exactly.

MS. TANGHETTI: Carbon free.

COMMISSIONER MCALLISTER: Great.

MS. TANGHETTI: We'll look for presenting those definitions once consensus is reached

COMMISSIONER MCALLISTER: Thanks.

MS. TANGHETTI: SB 100 context, once that definition is agreed on.

Okay, so back to greenhouse gas emission projections. These are not input to the NAMGas

Model but they're provided here as something of interest from our simulation results. The greenhouse gas emission projections for California are declining in all of the IEPR common cases. Again, the decrease between the April and our current draft projections for greenhouse gas emissions are mainly due to demand projections and, to a lesser extent, increased burner tip prices. So again, these are the trajectories for our common cases for greenhouse gas emissions.

Okay, this table provides, in much more detail, the numbers underlying the graph on the previous page. So recall that California is dependent on imported energy to meet demand. And this table provides the amount of greenhouse gas emissions projected to come from imports which you can find in the middle section of this table, and in-state generation, which is in the lower section of this table, with the total greenhouse gas emissions projected to meet California demand in the top section of this table. So again, these are just the numbers in the top section that underlie the chart before.

I think what's interesting from these

numbers, again, I didn’t put it on here, but are the ratio of greenhouse gas emissions by case from imports. While you can see the absolute value is decreasing, the ratio of import to in-state generation is pretty much constant in the mid and low demand cases, while the high demand case has a declining ratio of greenhouse gas emissions from imports.

This is really interesting because in the high demand case, California is actually projected to import more energy on an annual basis than the mid and low cases, but the import emissions for the high case are approximately the same as the mid demand case. In the high demand case, we’re projecting these imports to be less GHG intensive than the mid and low demand case.

Specifically, for the high demand case, we include an additional 5,000 megawatts of new wind in Utah, Wyoming and New Mexico, specifically added to meet the California RPS in the high demand case. I’ve added, again, a couple backup slides that you can find at the back of this presentation to look at the specifics on the year-by-year additions to meet the high and the low RPS in contrast to the mid, which was presented in the body of this slide.

COMMISSIONER MCALLISTER: Angela, what's your thinking about the possibility of other low-carbon resources in Utah, say? I know they're talking about building nuclear there. And sort of where that might pan out, in terms of California's market?

MS. TANGHETTI: In the WECC anchor data set, there is a modular unit included as part of the anchor data set by 2028.

What we're looking to do is, with our modeling efforts for capacity expansion, to include that as one of the options for the capacity expansion tools to pick. And if not, we'd like to look at it, even if the capacity expansion tool doesn't choose it, that we'd like to look at it, just as scenario to see how it impacts WECC-wide capacity margins, as well as greenhouse gas emissions. So we'd like to look at that as a scenario in the future.

So we do have the characteristics of it from the anchor data set and we're able to do that --

COMMISSIONER MCALLISTER: Oh. Great.

MS. TANGHETTI: Again, if anybody finds it of interest we can look at it again, since it's not included in this analysis. We didn't choose or we didn't include the modular nuclear but it is included in the WECC-wide anchor data set.

COMMISSIONER MCALLISTER: Okay. Great.

MS. TANGHETTI: So we should consider that.

COMMISSIONER MCALLISTER: Great. Yeah, I mean, I think that's helpful to have to inform the policy discussion that would, invariably, happen as we consider, you know, as -- if and when that happens, we need to make informed decisions. And your analysis will be key to that.

MS. TANGHETTI: Okay. We will look to doing that with these similar metrics for with and without the modular nuclear.

Okay, another interesting simulation metric is projected greenhouse gas emissions from a WECC-wide perspective. And this is a much simpler calculation than the California-only greenhouse gas emission calculations since a WECC-wide perspective does not need to account for imports or exports between regions in the WECC. These values simply represent the total greenhouse gas emissions based on fuel use by each generator in the WECC.

As you can see, the greenhouse gas emissions from a WECC-wide perspective are projected to decline over the forecast period, the high demand case, not as much as the mid and low cases since the existing fossil generation fleet is projected to operate at higher capacity factors due to lower reserve margins in the high demand case.

We're following utility IRPs and Trade Press for regions outside California to better understand how regions outside California plan to meet any projected capacity shortfalls.

Our next step for data set updates includes incorporating the California Energy Demand Forecast, once adopted, as well as more recent utility IRPs for regions outside of California.

There were many other details and results I wanted to share. But in the interest of time, I limited assumptions and results.

Whoops. I don't want that slide. Well, those are the backup slides I was talking about.

But again, I did limit assumptions and

results. So just please ask if there's other assumptions and results that may be of interest for future presentations or follow-up details from anything presented today. It's really difficult for me to pare down these presentations to my favorite results because, like a proud parent, they're all my favorite. So if you're interested in some metric not shown today just, please, contact us.

Thanks.

COMMISSIONER MCALLISTER: Thanks Angela.

MS. TANGHETTI: Sure.

COMMISSIONER MCALLISTER: I want to just say thanks for all the great work. And, I mean, I know you have your toolbox, maybe, for generation resources that allow you to cover, you know, 8760 and kind of get the results that are limited these days in terms of, you know, the further out we go the less clarity there is. So I appreciate your, you know, wrestling with all of that and informing us of your results, so thanks a lot.

MS. TANGHETTI: Right. And we look forward to more of those. It seems like our toolbox is limited but we seem to be coming up with more with the process ahead of us. And, you know, we're excited to look at offshore wind in our next set of simulations because it does have what they're calling a complementary profile --

COMMISSIONER MCALLISTER: Yeah. Exactly.

MS. TANGHETTI: This as well a modular nuclear, and maybe even some sequestration as well. So we're looking at considering all these in our next portfolio update.

COMMISSIONER MCALLISTER: Yeah. Great. I think that, you know, necessity is the mother of invention.

MS. TANGHETTI: Yes.

COMMISSIONER MCALLISTER: And having these conversations and looking at the tough questions is going to produce the results we need. And so you're really laying a good foundation for that, so thanks.

MS. TANGHETTI: Thanks.

MS. RAITT: Thanks Angela.

So next is Peter Puglia from the Energy Commission.

COMMISSIONER MCALLISTER: I wanted to point out something from Angela's presentation that's notable, to me at least, from Angela's presentation, was that, really, California policy the centrality of what we're doing in California, I mean, just looking broad terms, you know, two-thirds of the thermal retirements and two-thirds of the RPS-eligible electricity for the whole WECC is going to happen here in California. And so that's a huge market driver. And just, I think, we all should keep in mind how important what we're doing here in terms of long-term planning actually is because it's going to drive the whole market across the west.

MR. PUGLIA: Good morning, Commissioner McAllister.

COMMISSIONER MCALLISTER: Your mike.

MR. PUGLIA: Am I on?

COMMISSIONER MCALLISTER: Yeah, there you go.

MR. PUGLIA: Thank you. Good morning, Commissioner McAllister, Adviser Barrera, ladies and gentlemen, the audience. This morning I'm going to meet the Energy Commission's statutory mandate to report on -- we always keep the rules here. This is what this is about is that we don't need the cops to --

COMMISSIONER MCALLISTER: I appreciate

your extreme vision.

MR. PUGLIA: Yes.

COMMISSIONER MCALLISTER: That's great.

MR. PUGLIA: I'm an automaton. I only do what I'm told. Yeah.

And Assembly Bill 1257, the legislature named it the Natural Gas Act. It was passed and enrolled, chaptered in 2013, and it required, beginning with the 2015 IEPR and with every Integrated Energy Policy Report every four years, to report on compliance with a specified set of strategies and options the legislature identified in the statute to advance the use of natural gas in California in a broad variety of applications.

So my presentation of our compliance is pretty simple. I'll just go over what the statute required. Then I'm going to, because I'm an automaton and we always do what we're supposed to do as directed by those folks in the capital, I'm going to tell you what else the legislature has told us to do. This is legislation that impacts Assembly Bill 1257. And then I'm going to go into a little bit of detail about our compliance with that bill.

Okay, these are the ten sections,

separate sections that are included in the statute. These are just one-line summaries of what, as the statute reads, to identify strategies to maximize the benefits of natural gas. And there are pretty much two groups of strategies here. They're either optimizing -- the Commission is supposed to optimize natural gas in different types of applications or it's supposed to figure out what to do with it in different policy areas or applications.

As you can see, at the very end there's a requirement that the Energy Commission evaluate incremental economic and environmental costs of benefits of the proposed strategies that the Commission identifies.

These are -- there are 16 statutes that most of them of them have been passed since AB 1257 as passed in 2013. I split out these five because they're the ones that have a major impact on Assembly Bill 1257.

The first one, Senate Bill 1374, is a big deal because it sunsets AB 1257, the Natural Gas Act, and ends the quadrennial reporting requirement November 1st of 2025. A Senate floor analysis last year said that the sunset's consistent with efforts to ensure that long-term reporting requirements are not duplicative.

You probably recognize the other four statutes. These are separated from the batch of 16 that I'm identifying on this presentation, and I'll show you in a subsequent slide, because they set targets, either emissions targets or procurement targets in statute. And those targets, either for greenhouse gas emissions or for procurement of renewable resources, are going to have a major impact on the consumption of natural gas.

You're probably familiar with most of these. AB 32, Global Warming Solutions Act, which requires the Air Resources Board to adopt statewide greenhouse gas emissions limit at 1990 levels by 2020, or next year.

Senate Bill 350 requires 50 percent renewable energy resources by December 2030.

Senate Bill 32 requires the state to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030. CARB is the lead on that.

Senate Bill 100 increases 2030 Renewable Portfolio Standard target to 60 percent and adds a 100 percent zero-carbon electricity resources target by 2045.

The statutes identify these as targets because we might get there early, we might get there late. But for Energy Commission purposes, we are supposed to provide analysis that hits the target on the date the legislature specifies.

And if you're interested in more depth on these statutes, they are covered in depth in the rest of the IEPR.

These are the bills that have a minor impact. And largely, they have a minor impact because there are no specified emissions reductions or other targets. They offer tariffs, other subsidies that require the Energy Commission to perform assessments, or they identify program development or other proceedings that the CPUC would have to open.

And AB 118 has created the Clean Transportation Program. It uses funding for natural gas vehicles infrastructure in the past but was extended by Assembly Bill 8. And the Energy Commission proposals for future Clean Transportation Program funding under AB 118 and Assembly Bill 8 are that there isn't any more money going into natural gas vehicles or infrastructure.

Assembly Bill 1613, that’s the Waste Heat and Carbon Emissions Reduction Act. The CPUC runs this program for feed-in tariff for combined heat and power plants up to 20 megawatts capacity.

Senate Bill 1122 authorizes the Bioenergy Feed-In Tariff or the BIOMAT, Bioenergy Market Adjusting Tariff (phonetic). That’s another CPUC feed-in tariff program for small bioenergy renewable generators less than five megawatts.

There’s AB 1420 that required Division of Oil, Gas, and Geothermal Resources to review existing pipeline regulations. That has an impact on one of the specific requirements of AB 1257, requiring an infrastructure review. And DOGGR needs to have that update done by January 2018. They did.

Senate Bill 1383 requires Air Resources Board to develop a comprehensive strategy to reduce methane and hydrofluorocarbon gases by 40 percent.

Senate Bill 1369 specifies green electrolytic hydrogen as an end-user storage technology be targeted for increased use. You'll find that further in the presentation that hydrogen is identified as plausibly able to mixed in with a natural gas pipeline stream at low concentrations and then it can be used in a power-to-gas applications. I'll discuss that in a few minutes.

And Senate Bill 1440 requires the Public Utilities Commission, with the Air Resources Board, to consider adopting specific biomethane procurement targets for natural gas investor-owned utilities.

Senate Bill 1477 requires the CPUC to develop and administer these two programs, the Tech and Build Program that reduce building GHG emissions. Since about 90 percent of natural gas used in the California building sector in commercial and residential is used for heating, this is going to have a major impact on natural gas demand in California.

And it's by virtue of that, one of the particular requirements of Assembly Bill 1257, which I'm going to cover, is how to expand or optimize, is actually the term used, optimize the use of natural gas in those residential and commercial applications. And this presentation will show how that's reconciled between those two statutes.

Assembly Bill 3187 requires the Public Utilities Commission to open a proceeding by July this year to promote in-state production and distribution of biomethane. There's a lot of Energy Commission funding and research going into biomethane, not just subsidies to expand production. There are other agencies that are providing funding for that, too, for those kinds of projects. But also, rules to interconnect those biomethane supplies with the regular natural gas pipeline system. And I'm going to go into a bit of detail about that as well.

Finally, Assembly Bill 3232 requires the Energy Commission to make an assessment by January 2021 for the potential of GHG emissions reductions from residential and commercial building stock by at least 40 percent below 1990 levels, hitting that target by January 2030. But that's an assessment. It's not an actually specified target, which is the thing that's common with each of these statutes.

Assembly Bill 1257 required that the

Energy Commission develop all ten strategies in consultation with the Public Utilities Commission, the Water Resources Control Board, the ISO, Air Resources Board, Division of Oil and Gas, and Geothermal Resources, and the Department of Conservation. You'll see in this presentation that other legislation, such as the legislation I discussed, requires that these agencies also are called to meet similar requirements, not just us.

Here are the nuts and bolts of the ten requirements specified in AB 1257.

The first one is to optimize natural gas as a transportation fuel. How has the Energy Commission complied with this strategy? It's right here. The Energy Commission's Natural Gas Research and Development Program provided funding for in the Clean Transportation Program to support near-zero emission natural gas engine fueling infrastructure development. And as a result of this the total transportation sector and natural gas supply in California of renewable gas rose from 10 percent to 70 percent renewable gas out of the total transportation natural gas supply.

Second requirement of AB 1257 is to

determine the role of natural gas for our generation as part of the resource portfolio. This is a big target for greenhouse gas emissions reductions. What's been happening, you can see if you follow the proceedings, is an effort on the part of key stakeholders, the ISO, the Public Utilities Committee, the electric utilities, to maintain reliability and to support the integration of renewable resources which does give a lot of room for natural gas-fired generation to play a role.

You saw in Angela's presentation, she had, slide 10 or slide 11, she had gas, projected gas use for electric generation. And you're seeing that at the worst it's 350 billion cubic feet. But it could maximize -- it could max out at close to 600 billion cubic feet. So there's going to be, especially in transmission-constrained areas, there's going to be a role for natural gas-fired generation to support the continued deployment of renewable storage technologies and integration with those resources.

The third requirement of Assembly Bill 1257 is to optimize natural gas as a low-emission resource. The bulk of this is directed, as you can see, from the five bullets, it is at biomethane. That's where the future is. We'll see. And there's a lot of funding, both Public Utilities Commission, the California Department of Food and Agriculture, that's the third bullet, the California Department of Recycling and Resources Recovery, and also the Energy Commission funding biomethane projects.

Also, the Public Utilities Commission, as you see in the fifth bullet, they have a proceeding open to establish interconnection tariffs, as I mentioned earlier, open access rules and standards under -- in compliance with Assembly Bill 3187, in order to ease the transition from less 100 fossil natural gas in the state's pipeline system to larger and larger shares of renewable natural gas, especially biomethane.

The next requirement under AB 1257 is optimizing natural gas for heating, water heating, cooling, cooking, engine operations, and other end uses. Engine operations, of course, is largely industrial, some commercial. And as I mentioned before, homes are using about two-thirds of California’s natural gas and 90 percent of that is expended on space and water heating.

Currently, Energy Commission research, sponsored research, is attempting to meet the statutory requirements to reduce greenhouse gas emissions, which under scenarios that we have funded as laid out in the Energy Commission E3 Report, Deep Decarbonization and a High Renewables Future, is going to cut a lot of natural gas use in buildings, commercial and residential. However, opportunities will remain for natural gas to continue in applications where it just isn’t efficient to continue to transition to electric power.

The next requirement under AB 1257 is to identify implementation methods for electric and natural gas industries. As I mentioned before, gas-fired generation is going to be required under current proceedings to integrate renewable resources and to support load when other resources are not reliable of cost effective. And part of that gas stream, as I mentioned, is going to include biomethane.

Next is the requirement that the Energy Commission determined a need for a long-term infrastructure reliability policy. This is what I alluded to earlier about Division of Oil, Gas, and Geothermal Resources requirement to implement stricter pipeline safety regulations, which they did. They completed those.

Emission standards; the Air Resources Board stepped in to complete that, as it is their statutory requirement. And they implemented greenhouse gas emission standards for crude oil and natural gas facilities.

The Energy Commission has funded a lot of the research with NASA, JPL, and with other entities to use either aerial surveys or natural gas emissions from infrastructure or point-by-point on-the-ground surveys to develop inventories that would inform these regulatory rulemaking proceedings. This is important because, as a greenhouse gas, methane is 84 times as potent as carbon dioxide. It’s shorter lived. Its half-life is a lot shorter than carbon dioxide, which has a 50 year half-life. But if it continues to be emitted from these facilities, it will continue to be replenished in the atmosphere and we’ll have that kind of a climate forcing effect. So these actions are very well founded.

And as I mentioned earlier, there are going to be efforts. There is legislation, SB 1369, to attempt to integrate hydrogen into electricity markets, into energy storage technologies, power-to-gas where electrolysis is used to convert water to oxidize it into its hydrogen and oxygen components and then have it available for use to convert through fuel cells back into electricity. And as I mentioned before, existing natural gas infrastructure, depending on the materials used in the pipeline, can feasible take on 5 percent to 15 percent hydrogen-natural gas blends. The problem is that with too much hydrogen there is a phenomenon called embrittlement where the hydrogen rearranges the steel structure of the pipe and it turns into, instead of a tensile expanding, something that can assume the pressures of a transmission pipeline, it becomes brittle and it no longer has that tensile coefficient and it can shatter. So you are limited to the amount of hydrogen you can put into the infrastructure based on the pipeline materials.

Next, the Energy Commission is required to determine the role of natural gas in zero-net energy buildings. As of last year's 2018 IEPR Update, the currently enacted GHG Emission Reduction Policy initiatives support replacing zero-net energy policy goals with goals for low-carbon zero-emission buildings and also to integrate larger scale -- excuse me -- larger scale, spatial community block-scale technologies to reduce greenhouse gas emissions reductions. And that's covered in detail in last year's IEPR Update.

Finally, there's optimizing jobs development in the private sector, particular in distressed areas. This is already part of statute. This is part of Commissioners' votes in the past that SB 350 requires that there are fair and equal opportunities for economically disadvantaged and underserved communities to participate and to benefit from Energy Commission programs. And jobs development has been facilitated by research and development funding from Energy Commission programs for jobs in each of the technologies that I've mentioned before, dairy digesters, municipal solid waste, wastewater treatment plants, et cetera.

State law already requires that we

facilitate each of these proposed strategies with state and federal policy and entities. And we invite and have encouraged and received participation of all interested state, regional and federal agencies in the preparation of the IEPR. AB 1257, by statute, is supposed to be a report included with the IEPR.

And then finally, we're supposed to -- the Energy Commission is supposed to evaluate incremental and economic environmental costs and benefits of these strategies. The legislature tasked the Air Resources Board with these evaluations in Assembly Bill 32. And the Energy Commission performs these evaluations as a member of the AB 32 Climate Action Team with potential energy resource options, including impacts on natural gas and other fuels.

That is my accounting of our compliance with Assembly Bill 1257. Thank you for your time.

COMMISSIONER MCALLISTER: Thanks Peter. So I guess just pointing out again, you know, this -- we're trying to be precise and a little bit surgical here. But I think, you know, it highlights, particular I'm thinking of the zero-net energy conversation. You know, sort of when the goal was set it was -- it seemed like a little bit of a reductive conversation.

And now as we get closer to that and we really have to work through, actually, a building code update, you know, and determine what it is we're actually doing, it becomes clear -- it became clear in that process that the natural gas component of building consumption needed a more kind of subtle, you know, multifaceted conversation. And so we ended up, of course, with zero-net electricity buildings and sort of, in a way, deferring the natural gas conversation to the low carbon discussion that is ongoing, you know, sort of on the front-end, actually, at the moment and ongoing. And so I think that's entirely appropriate and will allow us to ask and answer the right questions going forward.

So, anyway, I appreciate that rundown. It's a complex policy landscape and a lot of statutory mandates that is going to be up to us to talk through and resolve and point out where they potentially conflict. So I appreciate your keeping track of all that.

MR. PUGLIA: Thank you.

MS. BARRERA: I have one question on your slide --

MR. PUGLIA: Yes, ma'am.

MS. BARRERA: -- seven. It's on, I think, the first requirement, optimize natural gas as a transportation fuel. There's a bullet that struck me, it says,

"State policies drove share of renewable natural gas in California's total transportation sector natural gas supply from 10 percent in 2013 to 70 percent in 2018."

And I'm curious what percentage of that renewable natural gas is produced within the state, if you know?

MR. PUGLIA: Renewable natural, how --

MS. BARRERA: Yeah.

MR. PUGLIA: -- what percentage of renewable natural gas in the transportation natural gas supply is produced within California?

MS. BARRERA: Yeah.

MR. PUGLIA: I would have to get that for you, Ms. Barrera.

MS. BARRERA: And just curious like what is your assessment of like the most successful state policies that drove that sharp increase?

MR. PUGLIA: Can I ask Melissa?
MS. BARRERA: Yeah. I'm assuming it's the LCFS effect but --
MR. PUGLIA: Yeah. Just you want my judgment about what's most successful, and SB 100, I think is the most successful in setting an achievable limit, plausibly achievable limit on greenhouse gas emissions.
Does that address your question, even in a general way, as a --
MS. BARRERA: Well, SB 100 hasn't been implemented yet. So, I mean, I was looking more for like existing state policies. Because the draft report (indiscernible) a lot of the CPUC proceedings that are, seem to me, being implemented, not fully implemented as of right now. And just to see that sharp increase is positive.
And I was just wondering, like which one of the state policies is responsible for the lion's share of that, you know, increase from 10 percent to 70 percent in five years?
MR. PUGLIA: Oh, renewable natural gas?
MS. BARRERA: Yes.
MR. PUGLIA: I would have to -- statutes

that are funding -- Assembly Bill 118, Clean Transportation Program and the statutes that support the development of dairy digester gas, municipal solid waste gas, those would be, typically, in-state sources. So is that a better -- does that answer that?

MS. BARRERA: Yeah. So --

MR. PUGLIA: If that helps you.

MS. BARRERA: -- our own Energy Commission programs for ARFVTP would perhaps be responsible for getting some of these --

MR. PUGLIA: Yeah.

MS. BARRERA: -- (indiscernible)?

MR. PUGLIA: Yeah. Energy Commission funding, it’s over -- exceeded $80 million. A lot of it is to leverage financing of these projects. And market terms on their own would not succeed in a market without that kind of subsidy. But those projects, especially the dairy digesters, the Energy Commission has provided a lot of support for those, in addition to CalRecycle, Department of Food and Agriculture, ARB.

Funding for natural gas vehicles on the demand side and on the supply side of these types of biomass gas-producing facilities, again, I can't give you the breakout of how much is being produced out of state.

MS. BARRERA: You mean renewable natural gas?

MR. PUGLIA: Renewable. Yeah, I'm talking renewable natural gas. About a little over 90 percent of the state's natural gas supply is from out of state for starters. But we're specifically talking about natural gas demand in the transportation sector, how much of that supply is from in-state sources? And my answer on that is that it -- the responsible legislation and the programs that were prompted by that legislation are the ones that are leveraging development of these kinds of biomass production facilities, especially in the Southern San Joaquin Valley, the dairies down there.

MS. BARRERA: Thank you.

MR. PUGLIA: You're welcome.

COMMISSIONER MCALLISTER: I wanted to just chime in, I mean, I think in terms of policy drivers. So I don't know about the in-state, out-of-state, but I did have a chance to go with some staff down to the dairy digesters a couple weeks ago and get a nice tour. And it's very clear, just looking at their presentation and, I mean, incredible hard work on the digesters. And the infrastructure that's going in, it's just really amazing, it's really impressive. And, you know, it's a big feed lot, some big dairy production facilities there that have the opportunity to just concentrate the dairy waste and use it very efficiently. And it's very clear from a cost stack that they presented that -- or the benefit stack, really, that they presented that the LCFS is driving all of this. It's just, it's huge. The subsidy levels are just drowning out everything else. And so there are a number of initiatives across the state but the LCFS is the big money.

And to the extent that some of the early electricity PPAs that were -- that from the electricity that was generated were some of these early biodigester projects so that, you know, the PPAs are with PG&E and so their long-term contracts are in place. Those will be respected as part of the bankruptcy. But actually, the dairies kind of would like to get out of those contracts because they can go over to LCFS and make more money. And so the market really is -- you know, the magnet that is, you know, sort of drawing everyone's attention is LCFS for the moment.

And so one question, I think, policy question that we have here is doing some scenarios around the future of LCFS. I mean, it's been a really amazing project -- program for the transportation sector. But here we are talking about other potential destinations for renewable natural gas or renewable gas and biogas. And right now they're kind of high and dry because there's not enough sources to go around all these different demands. And so I think that's, you know, an oncoming policy question.

But in terms of in-state and out-of-state, I have no idea.

MR. PUGLIA: I'll get that for you if I -- you know, it might be a bit of a search but --

MS. BARRERA: Thank you. It's just I was just curious.

MR. PUGLIA: Yeah. I'll attempt to get that for you.

COMMISSIONER MCALLISTER: It's a good question because, you know, when we talk about -- so the legislature has such a key role here in, you know, directing the agencies what to do, including ours, and in this case, in transportation, primarily the ARB, at least on LCFS.

I guess, so that we can be most helpful in those discussions, you know, this in-state/out-of-state question is really good because we know that that's important to the legislature and we know that when they make investment decisions they tend to prefer, I think rightly so, investments that happen right here in California and develop our economy. So it would be good to kind of at least know the landscape, you know, not that it's -- we don't have to own whatever it is, we just want to find out kind of what it is so we can be helpful in the legislative discussion.

MR. PUGLIA: Your discussion, Commissioner McAllister, prompted my memory, a conversation I had with Tim Olson. He identified LCFS and the federal RINs funding. Yeah, he said that the renewable natural gas market would look completely different, it would be unrecognizable without those funding streams. Yeah.

Thank you again.

COMMISSIONER MCALLISTER: Thanks Peter.

MS. RAITT: Thanks.

Next is Lana Wong from the Energy Commission.

MS. WONG: Good morning. Oh, okay. Good morning. Good morning, Commissioner McAllister and Ms. Barrera and members of the audience. My name's Lana Wong and I'm Lead Technical Staff on Southern California Energy Reliability. And I'm going to provide a winter outlook for Southern California. This outlook is based on gas balance analysis that I prepared, as well as the CPUC's Winter 2019-2020 Southern California Reliability Assessment and SoCalGas' Winter 2019-2020 Technical Assessment that were released earlier this month.

And just to give you some background of how we got here, and especially for those who have not been following issues in Southern California, so Aliso Canyon, one of SoCalGas' natural gas storage fields suffered an uncontrolled leak at one of its wells back in

October 2015. The leak went on for four months before it was capped. That put the agencies in crisis mode. And that set us down a path of looking at reliability and short-term reliability, given that Aliso Canyon was taken out of service. And we also looked at ways to mitigate that reliability risk.

And so after Aliso Canyon underwent additional testing, safety requirements and remediation, DOGGR and the CPUC allowed SoCalGas to being injections into Aliso Canyon in July of 2017 on a limited basis, basically trying to balance safety and reliability.

Then in October 2017, one of the SoCalGas' main transmission lines, Line 235-2, suffered a rupture, compounding the reliability risk. And so that's why we've been looking at season ahead at this short-term reliability.

But after having said that, it sounds really kind of doom and gloom, so I feel like I should get to the punchline, which is that we do have the best outlook this upcoming winter, you know, in three winters. So I'll go through the presentation to get to that point but I didn't want you to think that it's all doom and gloom.

Let's see. Okay, that didn't work.

(Colloquy Between Staff)

MS. WONG: Okay. This slide provides an overview of what I'm going to cover this morning. We'll look at current pipeline update, storage inventory levels. We'll look at supply assumptions for the Gas Balance Analysis and the scenarios that were run. And then we'll wrap up with an outlook for this winter.

So the good news is that Line 235-2 is finally back online after being out of service for more than two years. And Line 4000 is also back online. So Line 4000 was removed from service on September 19th, just this past month, to undergo validation digs. And that's basically verifying the results of inline inspection reports, that you go out into the field and make sure that what you see in the field is in line with what is on those reports.

So it's good news that those lines are back in service but it's somewhat tempered by the fact that we're not back up to where the system should be.

So the Northern Zone capacity, so on the far right we've got the 2018 CalGas Report rated capacity, and that's 1590 million cubic feet a day. And so currently we're at 990 million cubic feet a day, so we're still not back up to where we want to be but at least both lines are back in service, whereas last winter only one line was in service, that was Line 4000, and we were at 870 million cubic feet a day.

So this shows a map of the SoCalGas system and highlights where the transmission lines are located, and also where Aliso Canyon is located. You can see the Northern Zone's rated capacity at 1590 million cubic feet a day.

So one note is in SoCalGas' Technical Assessment, they project a further increase, this is in their most optimistic case, but they project a further increase in the Northern Zone capacity later in winter, in the February timeframe, that it could increase to 1250 million cubic feet a day. But there's considerable uncertainty surrounding that assumption and that is not posted on SoCalGas ENVOY. That's SoCalGas' electronic bulletin board. And the Energy Commission MPUC Gas Balance Center is we don't model or include that assumption.

So looking at where storage inventory

levels are, we're nearly the same as last year, so we're at 77.3 BCF as October 28th, and that compares to 80.5 BCF on November 1st. Giving a breakdown of that, we see that Aliso Canyon is full at 34 BCF. And the other three fields are not full at 43 -- that should be 43.3 BCF. I had updated the number and I guess I missed updating that sub bullet.

So one note. I did take a look at NOAA's extended weather forecast and it shows the one-month look ahead is 40 percent above average temperatures. I also took a look at the three-month outlook and that also shows somewhere around a 40 percent above average temperature for the Southern California region. So, I mean, that's good news for the gas system. And what it means is that if November has mild weather, there's the possibility of getting more injections into storage instead of actually using gas during the month of November. But one caveat to that is that new DOGGR Regulations that went into effect this year require shut-ins twice a year. And Honor Rancho is scheduled to be shut in for the last two weeks of November.

So this slide shows a comparison of some of the assumptions between the gas balance cases. And one of the main differences is that SoCalGas discounts its pipeline supply between 10 to 15 percent, whereas Energy Commission and PUC do not.

There's also a slight difference on Line 4000 return-to-service dates. Originally, it was projected to return to service November 15th, then it was accelerated to November 4th, and it actually came online last week on October 24th. So those changes won't have a material impact on the results that we'll look at.

And then the lower part of this table show some supply assumptions differences. And the differences are mainly with respect to interruptible supply. And you'll note that the Energy Commission probably has the most conservative viewpoint of how much interruptible supply you can count on during the entire month. And also noted is that our assumptions are in line with prior assessments.

So this slide shows the gas balance results. And so what is a gas balance? The gas balance is a projection of monthly supply and demand with injections and withdrawals captured.

And so in our summer assessment that we presented last May, we prepared gas balance cases that allows you to look at the buildup of inventory. And are you able to build up inventory by the beginning of winter, given the pipeline outages?

And then our gas balance cases for winter allow us to look at withdrawals to meet demand and whether there is sufficient gas to meet demand during the entire winter season.

So this slide just highlights key results. We've got a column for beginning inventory November 1st and ending winter inventory March 31st, and also whether there are any curtailments in the case. We ran multiple scenarios to capture weather and pipeline scenarios.

So the weather scenarios, we looked at average or normal weather demand, and also the cold weather 1-in-35 dry hydro cases. The demand forecasts or projections were obtained from the 2018 CalGas Report. So all three sets of analyses, we all used the same demand forecast from the CalGas Report.

And then the main difference with respect to supply is whether Line 235-2 and Line 4000 are in service. So we looked at both lines in service which is our current condition today. We looked at one line in service which is the condition the system was in during the last winter and the winter two years ago. And then we also looked at both lines out of service which there was a remote possibility of that, especially with both lines being out of service for a short portion this fall.

And so out of the scenarios, I call Row 1 our likely scenario, primarily because it captures current conditions, that both lines are in service, and that with our weather projections from NOAA showing warmer than average temperatures, then we're probably closer to normal weather than we would be to the cold weather scenario, 1-in-35 dry hydro. So in that case, we show no curtailments and sufficient inventory to make it through winter.

And if you look, all three cases, Energy Commission, PUC and SoCalGas, the results are in line. We may have slightly different ending inventory numbers but, you know, the message is the same, that there should be sufficient inventory under those conditions and no curtailments.

So that takes us --

COMMISSIONER MCALLISTER: Can I ask a quick question?

So the one thing here about this table that jumps out at me is there's a scenario, Scenario 4, where both lines are in service, the weather is challenging --

MS. WONG: Right.

COMMISSIONER MCALLISTER: -- where both agencies say there's no curtailment but SoCalGas says there is curtailment.

MS. WONG: Right. Right.

COMMISSIONER MCALLISTER: So I guess, well --

MS. WONG: So --

COMMISSIONER MCALLISTER: -- I don't know, what do you chalk that up to?

MS. WONG: So primarily, so when I mentioned the assumptions the main difference between the agencies' analysis and SoCalGas', they discount pipeline supply. So that particular case has pipeline supply discounted by 15 percent. So there, both lines in service --

COMMISSIONER MCALLISTER: Okay. Got it.

MS. WONG: -- is considered their best case, then they discount pipeline supply. So their case does show curtailments.

So the question about discounting, we just don't agree with discounting the pipeline supply. And in that particular scenario with the cold weather, you know, you would ask, would you actually see pipeline supply at a lower level? If we really did have a super-super cold, extended winter, for five months out of the winter your utilization would probably be higher on those pipelines.

COMMISSIONER MCALLISTER: Okay. So we're --

MS. WONG: So it's probably very conservative.

COMMISSIONER MCALLISTER: So we'd prefer that they not hedge their best in that --

MS. WONG: Case.

COMMISSIONER MCALLISTER: -- scenario? Okay.

And then does that -- when you say the definition of in service here, is that sort of at full pressure or is that at the existing --

MS. WONG: No. That --

COMMISSIONER MCALLISTER: -- pressure or --

MS. WONG: -- that is at the current.

COMMISSIONER MCALLISTER: The current pressure?

MS. WONG: And actually, the eight -- no, excuse me. The 990 million cubic feet a day that I presented on the earlier slide --

COMMISSIONER MCALLISTER: Um-hmm.

MS. WONG: -- is slightly a little higher than what we've included because at one point SoCalGas said with both lines in service, we'd have 950 million cubic feet a day supply. But what they actually posted when both lines came back was 990. So we're only capturing the 850 number, so we'd probably be a little bit better because of that supply.

COMMISSIONER MCALLISTER: Okay. Thank you.

MS. WONG: But, yes, we're not capturing the 1590, no.

COMMISSIONER MCALLISTER: Great. Thanks.

MS. WONG: And we also don't capture the higher, that remote possibility that you might get more supply later in the winter.

Okay, so that takes us to the final slide and wrap-up, that this is the best outlook in three winters, and that's primarily because both lines are back in service. During the past two winters there was no chance that you'd have both Line 235-2 and Line 4000 operating. So this is really the best outlook we've had in the last three winters.

However, that's tempered by pipeline constraints that continue through this winter. Use of Aliso Canyon may be necessary to meet that single peak-day demand. If we have a cold snap during the winter, we may need to use Aliso Canyon.

The findings show that core reliability is not projected to be at risk. There's some risk to non-core curtailments. So the core is the residential customer, small commercial. Non-core customers are electric generators and the industrial customers. But there's some risk to non-core customers and that's primarily because we do still have pipeline constraints this winter. But the risk to non-core curtailments is diminished with both lines in service. The findings show electric reliability can be maintained.

And lastly, this is something that we mentioned at prior workshops, and that is pipelines return to service is key to improving reliability.

That concludes my presentation. Thank you.

COMMISSIONER MCALLISTER: Great. Thanks very much, Lana. I really appreciate it.

MS. RAITT: Thanks Lana.

So this is Heather Raitt. I just wanted to make a real quick announcement for folks on WebEx. We are having some technical challenges, so there's a chance that we might drop off. But if we do, I apologize, and we expect to be back on within a few minutes. So, anyway, but hopefully we'll continue through with our last speaker.

Hazel Aragon from the Energy Commission.

MS. ARAGON: Good morning. My name is Hazel Aragon and I'm from the Supply Analysis Office. And today I will be presenting exploratory scenarios that our staff has modeled to better understand how different factors may impact the electricity system in 2030. These studies are our own and made from other public studies.

I will start by talking about the base assumptions used for all cases, as well as the assumptions used for each of the exploratory scenarios. The first five scenarios that you see listed here are modeled in 2030 and use some level of electricity or considers a possible drought. The last scenario looks at a business-as-usual case in 2035. Finally, I will discuss the metrics we use to analyze these results.

So the 2030 mid-demand base scenario, which is a business-as-usual scenario, or a reference case, uses the following assumptions listed. We built the exploratory scenario's assumptions on top of these.

So we are assuming a 60 percent RPS target by 2030, as noted in SB 100. We are using the 2018 California Energy Demand Forecast Update 2018 to 2030 which was published on February 5th this year. The most recent Demand Forecast Preliminary IEPR 2019 was not used for these scenarios. We are using existing renewables and planned generator retirements which Angela mentioned in her presentation earlier today. We included 2,100 megawatts of additional battery storage, as noted in the CPUC's IRP process.

The next bullet point is an error. We are actually assuming 70 percent, not 75 percent of renewable energy which needs to come from in-state, and 30 percent from out-of-state.

RECs can be transferred from one year to another. We are using WECC-wide RPS policies as of December 31st, 2018. So any new RPS policies from this year are not included. And unless otherwise noted, we are using a 2003 to 2017 15-year average hydro profile.

So this slide shows each scenario's statewide net energy for load, the total RPS energy needed to achieve the RPS target, and how they compare to the 2030 mid demand base. The statewide energy net load includes imports. The total RPS energy is the sum of the total statewide retail deliveries, excluding pumping, plus any additional load times the RPS target. The low hydro scenario uses the 2015 WECC-wide hydro profile to model a drought year in 2030. No other major assumptions were made in this scenario. As a result, neither the net energy nor the RPS energy changed.

Our Demand Analysis Office provided us a transportation load profile that increased the current 3.6 million light-duty electric vehicles in their model to 5 million. But we chose to scale this profile to 10 million electric vehicles instead because we found that 5 million electric vehicles barely makes an impact to the electricity system. With 10 million electric vehicles, we added approximately 27 terawatt hours of load to the transportation electrification scenario.

Our Demand Analysis Office also provided us the building electrification demand profiles which is about an additional 33 terawatt hours added to the building electrification scenario. The high electrification scenario uses the combined additional loads of the transportation electrification scenario and the building electrification scenario. The low hydro with the high electrification scenario is the combination of the low hydro and the high electrification assumptions. And all these scenarios I've mentioned are in 2030.

COMMISSIONER MCALLISTER: Hazel, can I

just jump in real quick?

MS. ARAGON: Sure.

COMMISSIONER MCALLISTER: So a quick question, just clarification.

So for 2030, your analysis is showing that building electrification, the high building electrification scenario has a bigger impact on demand than transportation electrification?

MS. ARAGON: I am saying that the additional load in the building electrification scenario is larger than --

COMMISSIONER MCALLISTER: Larger?

MS. ARAGON: -- in the transportation --

COMMISSIONER MCALLISTER: Interesting.

MS. ARAGON: -- electrification scenario.

COMMISSIONER MCALLISTER: Interesting. Okay.

MS. ARAGON: And the last scenario you see here is the -- is modeled in 2035. And we extrapolated the WECC-wide demand forecast to 2035. And California has a negative average annual growth. And we took the average annual growth of 2017 to 2030 which is why the net energy in 2035 is lower than in the 2030 mid demand base case. However, the RPS energy is higher in 2035 due to a 70 percent RPS target.

This chart shows each scenarios' existing and projected total in-state capacity to meet the RPS targets. We did not add out-of-state capacities because we can't assume that other states will build additional renewable capacities to support our policy goals. The exploratory scenarios contain only additional solar and wind to meet the RPS target, so we did not include other technologies, such as offshore wind or carbon-captured technologies to any of these scenarios. Again, this is because we just want to limit our assumptions and test what we are using here for these scenarios.

The 2030 mid demand base scenario contains almost 40,000 megawatts of mixed resources to meet our 60 percent RPS targets. If we look at the high electrification scenario, for example, we may need about 13,000 megawatts of additional solar and wind capacity to meet the same target.

This chart summarizes other assumptions used in exploratory scenarios, including the RPS percent target used, additional battery storage used on top of the 2,200 megawatts added to the base assumption, and a hydro profile used where average means the 15-year average profile and low uses the 2015 drought year. And you may notice that in the building electrification scenario, it's the only scenario with additional battery storage. And we chose this scenario to test specifically how much battery capacity is needed to meet an applying reserve margin, which I will soon talk about.

COMMISSIONER MCALLISTER: So just to -- so I was going to jump on that to ask. And so you're going to tell us how the high electrification scenario with the combination of transportation and buildings avoids the need for that additional storage or --

MS. WONG: Can you repeat the question? I'm sorry.

COMMISSIONER MCALLISTER: So I guess the -- so we have building electrification, which is where you just said, you know --

MS. WONG: Um-hmm.

COMMISSIONER MCALLISTER: -- that there's the extra 1,200 -- I guess that's what? -- megawatts capacity in storage.

MS. WONG: Um-hmm.

COMMISSIONER MCALLISTER: And then but it's not present at the high electrification scenario which also includes all the building electrifications; right?

MS. WONG: So we are only adding the 1,221 to the building electrification scenario. This isn't seen in the high electrification case.

COMMISSIONER MCALLISTER: Okay. So --

MS. WONG: So that extra capacity is not there, no.

COMMISSIONER MCALLISTER: Okay. So you'll describe why, those choices? I'm just interested in sort of what the information -- so when you combine building electrification with transportation electrification in that overall high --

MS. WONG: Um-hmm.

COMMISSIONER MCALLISTER: -- electrification scenario --

MS. WONG: This part is not --

COMMISSIONER MCALLISTER: -- the choice was not to put that additional storage in?

MS. WONG: Correct.

COMMISSIONER MCALLISTER: Okay.

MS. WONG: So after running this

scenarios, one metric we looked at reserve margins. The reserve margin determines whether the electricity supply is able to meet demand at the time of system peak. The reserve margin takes into account forced and maintenance outages, as well as net imports. This table shows the lowest percent reserve margin and its corresponding hour at a given year. This is an important metric to consider because available capacity must always exceed the required energy in the system. So supply would be very hard to meet demand at a very low reserve margin, such as four percent.

These scenarios show they are typically occurring in the evening of the late summer or early fall. If we look at the low hydro scenario the minimum reserve margin does not occur at the same hour as the 2030 mid demand base case and is found to be the lowest on August 19th instead. And this is due to hydro re-dispatching the system in our model.

The building electrification scenario, which I mentioned, includes the additional 1,221 megawatts of battery storage, is not added. This capacity is not added to any other scenario.

Without this extra storage, we would be seeing a minimum of a reserve margin of 11 percent on September 3rd at 6:00 p.m. But by adding this extra capacity we're able to actually raise the minimum reserve percent margin to 15 percent. So we were just experimenting how this extra capacity might test the reserve margins.

And this slide is similar to the previous one but the focus here is what the reserve margin looks at the -- looks like at the maximum load in the given year. Besides the 2030 mid demand base, both the building electrification and high electricity cases are the only scenarios where the minimum percent reserve margin occurs at the same time as the max loads.

If we look at the low hydro scenario again, the minimum of the reserve margin is higher than the 2030 mid demand base case. This is due to how the model is dispatching generation during a drought year. We found that there was less forced and maintenance outages occurring at that hour, so there is more available capacity at that hour compared to the 2030 mid demand base case.

We limit the total peak net import using a constraint in our model such that no more than 13,100 megawatts can be imported during peak hours. However, this constraint does not apply to non-peak hours.

This slide shows histograms for each scenario. Each histogram is divided into percent reserve margin brackets containing the number of hours that fall into that bracket. So, for example, if we look at the low hydro with high electrification scenario, the bottom middle one, 42 hours during that year fall between the percent reserve margin of 14 percent to 19 percent, which is the first bar, and 1,671 hours falls between the 38 percent to 43 percent reserve margin which is the highest bar you see.

So another metric we looked at was natural gas consumption for electricity use. This chart shows how much natural gas was used in California, which is in blue, and the rest of the WECC-wide, which is in yellow. Despite additional renewables for the scenarios that included them, natural gas consumption increases compared to the mid demand base case. The additional intermittent renewables that we added may not generate at certain hours and, therefore, are replaced with natural gas.

If we look at natural gas consumption on a monthly basis in California only we see which months demand more natural gas use than others. The dashed green lines are the exploratory scenarios comparing against the blue solid lines, which is the 2030 mid demand base case. And these units are in billion cubic feet.

If we look, for example, at the low hydro scenario, we see that this case uses more natural gas during the warmer months, whereas if we look at the building electrification scenario, which is the top right scenario, we see it actually uses more natural gas during the colder months.

If we look at natural gas consumption on an average hourly basis, these charts basically portray that. We chose a cold month, January, and a hot month, July, to see roughly what time of day there is more natural gas used for electricity. The blue lines represent the average hourly natural gas use in January, whereas the yellow lines look at July. The dotted lines are the exploratory scenarios comparing against the solid line 2030 mid demand base case. And these units are million cubic feet.

And this is helpful to see how the average daily shapes compare between scenarios, what hours the gas use peaks, the magnitude of difference and/or shifts in the natural gas use hours.

COMMISSIONER MCALLISTER: So, Hazel, can I -- I want to just --

MS. WONG: Sure.

COMMISSIONER MCALLISTER: -- jump in. And so I think this is a really key -- this is kind of the money graph here, in my view, at least one of them. And as many of you know, I'm a big fan of trying to figure out how we can cultivate demand flexibility. And I guess I'm interested to hear sort of what that discussion, well, the background discussion on that and maybe what your definition of storage is. You know, how much has demand flexibility, demand response, you know, demand-side flexibility resources, other than just straight electricity storage, factored into this discussion?

MS. WONG: We've only tested the, I guess, storage in terms of battery storage in the building electrification scenarios. So we have not done much testing with other types of storage or other types of, right, other types of storage for the other scenarios, so it is something we could look at.

COMMISSIONER MCALLISTER: I think the -- even beyond storage, certainly there are thermal storage options, you know, that are complementary to battery storage or straight electricity storage. And then, also, load flexibility. I mean, we have to consider that as a way to shift around some of the renewable generation and avoid, perhaps, say on a low hydro year --

MS. WONG: Um-hmm.

COMMISSIONER MCALLISTER: -- just having our solution be ramp up the gas generation.

MS. WONG: Right.

COMMISSIONER MCALLISTER: Because that seems like that's one of the big differences between these scenarios, certainly between the electrification-oriented scenarios. As we increase demand we've got to figure out ways to shape that demand to respond to the renewable supply. So --

MS. WONG: Okay.

COMMISSIONER MCALLISTER: -- and so I

think that's worth digging into from, you know, here going forward.

MS. WONG: No. That works. We'll look into flexibility more.

COMMISSIONER MCALLISTER: Thanks.

MS. WONG: So going back to this slide, a scenario, such as the transportation electrification scenario, which is the top middle chart you see, shows lower gas consumption during the day for both months, for both January and July, because solar energy is meeting its demand. But natural gas use during -- but there is more natural gas use during the night, perhaps when everyone is charging their electric vehicles.

The last metric we looked at was how GHG emissions were impacted in the different scenarios. And there's an error on this slide. The units are in metric tons over megawatt hours, not million metric tons over megawatt hours. Beginning with emission intensities, we noticed that in the current drought raises the emission intensity factor more than any other assumption used. The low hydro scenario and the low hydro with high electrification scenarios both have an emission intensity of 0.17, which is a 0.02

increase from the 2030 mid demand base case. And as we noted earlier, these scenarios use high natural gas consumption for electricity.

This slide compares the in-state emissions, in blue, and the emissions associated with imported electricity, in yellow, for each scenario. For most scenarios, the out-of-state greenhouse gas emissions are relatively constant compared to the in-state's; 2035 is an exception. 2035 shows a bigger disparity between in-state and import emissions.

So while the total emissions produced from electricity generation is lower than in the other exploratory scenarios -- I'm sorry. Let me start over.

While the total emissions produced from electricity generation is lower in the 2035 scenario than the other exploratory scenarios, the in-state emission is relatively higher for the import emissions. And we found that California is actually importing more -- sorry, exporting more generation to the other states because the other states are trying to meet their own loads.

As mentioned earlier, we did not include additional out-of-state capacities for 2035. However, if we did, the total California emissions may be lower than the 2030 mid demand base case.

COMMISSIONER MCALLISTER: Hazel, it would be interesting -- I know this is not really in your brief here but, you know, the transportation electrification, and certainly with -- and building electrification, and even more so with low hydro, to the extent that puts upper pressure on emissions in the electric sector, it seems like it would be good to, alongside that, point out the avoided emissions of having the vehicles and the buildings move over --

MS. WONG: Okay.

COMMISSIONER MCALLISTER: -- just for kind of a comparison. You know, when you count the molecules, what does that kind of look like in terms of, you know, what autos are not emitting carbon dioxide because they're actually using electricity?

MS. WONG: No. That's a good point. Thank you.

This table highlights the percent of net imports meeting the total California loads. In all cases, we are net importing less during the year and, generally, because California is able to meet most of its loads with higher renewables. For the low hydro scenarios, we assume WECC-wide drought. As such, the rest of the WECC is trying to meet their own loads and there is less generation coming into California. I found this table particular helpful to see how the net exchange of generation between California and the rest of the WECC looks like between scenarios. And as mentioned previously, we are exporting more generation in 2035 which is why you see a lower percentage here.

This concludes my presentation. If you have any additional questions or comments, feel free to contact me.

Thank you.

COMMISSIONER MCALLISTER: Thanks very much, Hazel.

Did you have any more questions?

MS. BARRERA: No, I don't.

Thank you very much.

MS. WONG: Thank you.

COMMISSIONER MCALLISTER: I will just point out that we are eight minutes ahead of schedule, but you got to claim credit where credit is due.

And I think that moves us into public comment.

MS. RAITT: So we're just getting the timer set up. Excuse us.

(Pause)

MS. RAITT: So I think, Commissioner, that you have a blue card. We could go ahead and --

COMMISSIONER MCALLISTER: Sorry. Somebody slipped it in here.

Tim Carmichael from SoCalGas.

MR. CARMICHAEL: Thank you. Hello, Commissioner McAllister, Ms. Barrera. Just a few comments. I'm surprised that you're not flooded with blue cards, given the importance of the topic. Thank you for the opportunity to provide comments this morning.

SoCalGas appreciates the State of California's bold efforts to address climate change concerns. And SoCalGas remains a key partner in helping California lead the way to achieving dramatic reductions in greenhouse gas emission reductions -- dramatic reductions in greenhouse gas emissions.

Natural gas and renewable gases, such as biomethane and hydrogen, are clean, reliable, affordable and resilient sources of energy that will be part of the solution to California’s energy needs. With these important climate goals in mind, we believe that a portfolio approach utilizing all energy sources and technologies increases the likelihood of success and will best serve Californians in the most cost-effective and sustainable manner as the Commission is required to identify strategies to maximize the benefits obtained from natural gas and renewable natural gas as an energy source, helping the state realize the environmental and cost benefits afforded by these fuels.

SoCalGas believes that the Energy Commission should provide sufficient consideration and effort to meet the statutory requirements of AB 1257 and recognize a balanced energy solution supported by a technically-valid, comprehensive and robust report. SoCalGas continues its commitment to engage CEC staff to support the development of this report.

And we will be providing written

comments.

Thank you.

COMMISSIONER MCALLISTER: Great. Thanks for being here.

Any other comments in the room? All right.

Do we have anybody on the WebEx?

MS. RAITT: I do have one written comment I can read.

Do we have more? No. Okay.

So --

COMMISSIONER MCALLISTER: Has the WebEx been going well? Have we had any --

MS. RAITT: Yes. We haven't dropped as far as I know.

COMMISSIONER MCALLISTER: Okay. Great.

MS. RAITT: So folks should still be with us.

So I will read this. It's sort of like questions, but I think it also serves as comments. So it's from Sam Wade. It starts off, "The LCFS is absolutely the driver for the RNG use in transportation."

Then he goes on to say,

"I'm a bit confused about how the AB 1257 appendix work will relate to the recently released work from E3. Peter highlighted the importance of building electrification and E3's work as a long-term driver of building decarbonization. But that work has also consistently shown that the use of renewable natural gas derived from biomethane is a complementary policy to building electrification and is an essentially near-term strategy for hitting our 2030 greenhouse gas reduction goals.

"Will the appendix discuss the role that renewable natural gas can play, especially in the near term in decarbonizing buildings, as required by AB 1257, until demand reduction occurs through electrification and efficiency?

"Will it discuss policies that could facilitate taking advantage of renewable natural gas as a low-emission resource, including providing additional information about implementation of the biomethane procurement programs authorized in SB 1440?

"Will anything in the appendix build off of the RNG supply analysis in chapter nine from

the 2017 IEPR, which we thought was well
done?"

And I'll just note that chapter nine in the 2017 IEPR was on renewable gas.

And that's it.

COMMISSIONER MCALLISTER: Well, that was a great set of questions. So, hopefully, people who have heard them can formulate some comments that take some of those things into account.

Let's see, certainly in terms of -- well, I'll just say the broader landscape, you know, we talked a little bit about some of that earlier, but -- well, I'll just leave it there. So hopefully people can figure out what they think the most relevant comments are. I do think our path forward for decarbonizing our buildings and the things that commenter mentioned are very worthwhile to understand within this broader context we've been discussing today, so thanks.

MS. RAITT: Okay.

COMMISSIONER MCALLISTER: Is that it?

MS. RAITT: Any other comments? No.

So I'll just remind folks that we are going to extend the public comment period to November 27th, and we'll putting a notice out to that effect, so --

COMMISSIONER MCALLISTER: Okay. Great.

And just finally, I think, you know, the future of natural gas work that we've been doing is ongoing. That report, actually, I believe, has been posted now, the E3 Report, so that's now out in the world to be commented on.

And, you know, optimization is a word that means different things to different people. And so, you know, what is the optimization of our natural gas strategy and our natural gas future going forward in the context of decarbonization? I mean, this is kind of the question of our times.

So I appreciate everybody putting their thinking caps on to provide us with some input on our various paths forward because there's not just one here. There are lots of rule makings and lots of work going on, both here and across the agencies. So appreciate everyone's commitment to these topics and to finding solutions that work for California.

Linda, any additional comments?

MS. BARRERA: No, I don't have anything to add.

Thank you so much for being here. And I look forward to having a draft report published in the near future.

COMMISSIONER MCALLISTER: Yeah. So again, comments, the 27th, we'll post it. It will be at least two weeks before the 27th. And then people should submit comments by the 27th.

So thanks everybody for being here. I really appreciate it.

And we are adjourned.

(The workshop adjourned at 12:14 p.m.)

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.

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IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of December, 2019.

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