DOCKETED

Docket Number:	17-IEPR-04
Project Title:	Natural Gas Outlook
TN #:	219967
Document Title:	Transcript of 04/25/2017 IEPR Lead Commissioner Workshop Natural Gas Scenarios/Natural Gas Outlook
Description:	N/A
Filer:	Cody Goldthrite
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/28/2017 2:29:46 PM
Docketed Date:	6/28/2017

BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:) Docket No. 17-IEPR-04
)
2017 Integrated Energy Policy)
Report Update *IEPR)*)

IEPR LEAD COMMISSIONER WORKSHOP

Natural Gas Scenarios/Natural Gas Outlook

CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
Art Rosenfeld Hearing Room (Hearing Room A)
Sacramento, California 94203

TUESDAY, APRIL 25, 2017

10:00 A.M.

Transcribed by:

Kelly Farrell,

Certified Shorthand Reporter

CSR No. 8081

APPEARANCES

Commissioners Present

Robert Weisenmiller, Chair CEC
Andrew McAllister, Commissioner CEC

Staff Present

Heather Raitt, IEPR Program Manager
Jason Orta, Energy Commission Staff
Anthony Dixon, Energy Commission Staff

Panelists Present

Michael Thomas, BP Energy
Kathryn Dyl, Energy Information Administration, (Via WebEx)
Rose Marie Payan, Sempra Utilities

Public Comment

Bill White (Via WebEx and as read by Mr. Raitt)

Also Appearing

Matt Coldwell, Commissioner Scott’s Office

I N D E X

P R O C E E D I N G S

10:00 a.m.

MS. RAITT: Good morning, everybody. Welcome to today's IEPR Joint -- IEPR Workshop on Natural Gas Issues.

I am Heather Raitt, the Manager for the IEPR.

A couple of housekeeping items. If there is an emergency, please follow staff to Roosevelt Park, which is diagonally across the street from the Energy Commission.

Please also be aware that this is being broadcast through our WebEx conferencing system, and it is being recorded. We'll post the audio recording in about a week and a written transcript in about a month.

At the end of the day, we'll have an opportunity for public comment, and we'll limit that to three minutes. You can fill out a blue card and give it to me if you want to make a comment at the end of the day. Also, you can raise your hand up, tell our WebEx coordinator that you would like to comment at the end of the day.

Materials for the meeting are available at the entrance to the hearing room and on our website.

And comments, written comments are welcome and due on May 9th. And the Notice provides the information for how to submit written comments.

And we have do have some time constraints today, so we'll be adjusting the schedule a little bit, probably, to move Anthony Dixon before the break. But planning to break at the scheduled time, at 12:15.

And, with that, I'll turn it over to the Chair.

CHAIR WEISENMILLER: Good morning. Thank you for being here today.

We're dealing, obviously, with starting to set the framework for the natural gas scenarios with this IEPR.

Obviously, the natural gas scenarios, so this work, will have a big implication on some gas prices, which will, in turn, affect retail rates, which will, in turn, affect a lot of our cost-effectiveness analysis. And, so, that's one of the key things.

The other is there is a lot of change in the natural gas market at this point. So, trying to understand that dynamic as we go forward and, particularly, as part of the overall transformation we're dealing with in terms of reducing greenhouse gas emissions.

So, again, thanks for your help on this.

MR. COLDWELL: My name is Matt Coldwell. I'm an advisor in Commissioner Scott's office. And, so, she sends her regrets for not being able to participate today but was really looking forward to this morning's and this afternoon's discussion. So, she wanted me to sit in for her in her place and take some good notes for her and report back to her when she's back in the office.

So, thank you for having me and look forward to the discussion today.

MS. RAITT: Thanks.

Our first speaker is Jason Orta from the Energy Commission.

MR. ORTA: Good morning. My name is Jason Orta, and I am with the Energy Commission's Natural Gas Unit, which is located in our Supply Analysis Office.

The purpose of this presentation is to talk about our natural gas modeling, which provides forecasts of supply, demand, flows and prices.

One of the key elements of this model is that it's a North American model. So, it not only includes California, but it also includes the other 47 continental states, Alaska and Mexico.

Also, keep in mind that this model produces annual estimates. It's not a monthly model. And by virtue of this being an annual model, it does not include natural gas storage because, to model that, you'll need monthly changes in injections and withdrawals of natural gas. So, this model does not include storage.

And another thing we're going to talk about in addition to supply, demand, flows and prices are market trends, in particular, how they affect California.

The model that we use is known as the North

American Market Gas Trade Model. Also, known as NAMGas. And, so, within the NAMGas model, one of our inputs includes assumptions on demand in disaggregated sectors. And our estimates for demand are derived from what we refer to as "The Small M Model." It's a model --it's a model that goes into the big NAMGas model.

So, in modeling demand in these various sectors, you look at -- here, each of these include the sectors that we have, residential, commercial, industrial, power gen, and transportation. But if you look across the list, some of these items are common and are similar across these categories.

For instance, The Small M Model really relies a lot on historical information, so you'll see in a couple of these categories that recent historical demands for natural gas in these sectors is an assumption.

In addition, in the power gen side, we also include historical information on electric generation from other resources, coal, nuclear, hydroelectric, and renewable resources. And, also, this is the part of the model where we make our assumptions on coal retirements, increased renewable penetration into the market. So that's included in here as well.

Another variable that we look at here is weather, particularly in residential. Actually, in all of these categories, except for transportation, we look at weather. It's cold weather; except for in the power gen, we look at -- we look at hot weather as well because the demand in that sector is going to be mainly for cooling during the summer months. So, this model, within the model, includes inputs regarding heating and cooling degree days.

Another thing to keep in mind is that most of these -- this mainly applies to forecasted demand outside of California. What we mainly use for demand in our model is the state's California Energy Demand Report. The 2015 report is what we use here.

Another very important consideration here is the cost of developing potential resources. And, so, over the last decade, that -- those costs and those potential resources have changed a lot. What this graph is basically telling you is that more resources can be developed at each -- each of these different cost points. This is due to changes in technology. This is a part of the model that's very important because, as our proved supplies deplete over the years, there's going to be the need to develop these potential resources to meet future demand.

Another thing that we need to do is we need to update this for 2017, and that is something that we will do in our next set of runs.

So, the simplified view of this model, this is an economic model. And what it does is it connects supply basins with pipelines, which are connected to demand centers throughout the continent. And it's an iterative model, so it goes back and forth amongst these different segments. And it's basically a negotiation for, you know, what are you willing to sell at what price or what are you willing to buy at what price. So, it's iterative throughout the time period of the model and also throughout all of the regions.

So, we've constructed three models -- three runs based on the IEPR Common Cases. We started with a mid-demand case, which is also our reference case. From there, then we build out the low-demand case and the high-demand case. And one of the things that we struggle with internally is the nomenclature. So, before I continue, a reminder that the low-demand case can also be looked as the high-cost, high-price case. The high-demand case can be looked at as the low-price, low-cost case as well.

I mean, this is something that we struggle with, but we try to keep the nomenclature consistent but also easy to follow.

The next couple of slides will go through assumptions that we used in our modeling. The first one, we use the EIA's assumptions for economic growth in the low-, mid-, and high-demand cases. The mid-demand case assumes 2.2 percent economic growth. The low is 1.6 annually. And 2.8 in the high-demand case.

The next couple of slides are -- I'm sorry. The next couple of rows pertain more to the energy sector, so we also incorporate for California assumptions from the 2015 IEPR on Additional Achievable Energy Efficiency. For renewables, we assume for all cases that California will meet its 50-percent target by 2030 and other states will meet their RPS targets as well.

We also include assumptions on coal retirements. In the high-demand case, we expect more coal retirements than in the mid and the low case, as coal is a substitute for natural gas.

But this slide here, these variables, these assumptions here, you know, based on your intensive work with this model and doing, I think, what we can do in our office maybe conservatively to rerun the data more -- and we run this quite often -- is that what really drives the differences amongst the results you're going to see in these scenarios are these assumed costs.

So, the mid-demand case uses what was inputted for 2015 for the potential to develop the potential resources and also for the forward costs, which are the development, which is the production from existing resources. We use an estimate that we have based on hub prices as well.

So, the differences, the 30 percent higher cost on the -- on the low-demand case -- I get tied up with this, too -- and the 30 percent lower cost on the high-demand case, 30 percent higher cost in the lower-demand case, that's where you're really going to see -- it's from those you're really going to see -- that really results in the differences amongst the prices.

So, in producing this model, and as I mentioned earlier, we used this model, this econometric model that we call Small M, to build reference demand assumptions for each of these cases.

And, so, looking here for in the mid-demand case between now and 2030, the expectation is that demand for natural gas in the United States will grow by three trillion cubic feet, and within the power sector, that's going to -- about a million of that -- I'm sorry, a trillion of that will come from demand growth in the power sector.

Another sector that we expect to see some growth in demand is also the industrial sector, with the residential and commercial sectors kind of remaining flat.

So, by 2030, you'll see that it ranges -- that U.S. demand will range from 24.5 Tcf on the low-demand side to 30 Tcf on the high-demand side. And a lot of -- so this -- these numbers assume, you know, these are from that Small M Model, which includes the various cases for economic growth, renewable integration, and coal retirements.

So, for California, again, a lot of this is based on the California Energy Demand Forecast and also, at least in the power gen sector, it also -- these are results from the PLEXOS power dispatch model run done by our colleagues in the supply office.

So, if you look -- I mean, we're looking at very -- you know, while the rest of the country we expect, at least in the mid and the high cases, we expect so growth in natural gas demand as a whole and also within the power gen side, we're assuming, at least in the low-, and mid-demand case, by 2030, we're going to be using less natural gas in California as we did in 2016. And in the high case, it's going to be higher than what it is in 2016, but it's not going to be the kind of growth that you're going to see in the rest of the country.

So, the next few slides are going to be model results as they pertain to the United States. And, then, after that, we'll talk about model findings related to California.

This slide here shows our forecast of prices at the Henry Hub pricing point, which is the benchmark price in North America for natural gas. So, what we did with this model is we started in -- well, I shouldn't point with a pen, because they cannot see the pen online and -- well, you guys can't even see it here either. But, anyway, I'm going to use the mouse there. I was reminded by one of them yesterday to do that, but, anyway --

So, for 2014 through 2016, we use historical data to try to calibrate the model. And you can see that prices, those average annual prices were pretty high in 2014. That was a very cold winter. That was the polar vortex winter in January, February of that year. And then you'll see prices go down in 2015 and 2016.

But, looking ahead -- but what also happened going back before 2016 is this that there was -- there was a lot of supply out there, there was growth and production of dry gas every year from 2005 to 2015. In 2016 -- excuse me -- that number dropped a little bit. So, all that kept prices low. But going past 2017 and beyond, we will expect more of those existing resources to be depleted. And, then, over time, there will be development of potential resources, which would require capital, an upfront capital investment to develop those new resources. And those are going to be reflected in these price increases over time.

Another thing that our model is showing is that -- and we'll see more of this in the next few slides -- is that demand is growing at a faster rate than production throughout the United States.

And, again, so as we saw earlier with California, gas demand is expected to climb. But in the United States, in the mid-demand case, we're looking at roughly a 0.7 percent per annum growth rate in natural gas demand. And a lot of this is coming from the power -- the power sector, as you can see here. Especially, in the mid to high cases, there's going to be -- especially the high cases there's going to be some growth. Which makes a lot of sense, is that once, you know, in reducing in the high-demand case if you're assuming cost to drop by 30 percent to develop proved resources and then to bring online potential resources, those costs -- those low costs are going to translate into lower prices, which would lead to hire demand in the future.

And, so, for -- particularly in the high case, you could see here in the power sector that the growth of demand for gas is pretty substantial in the high-demand, low-cost case.

And this graph here looks at production. So, one thing to look at here is that if you look past -- if you look around 2019, 2020, you'll see some growth in production. What triggers that is that our model is showing a bump in prices in 2018. And that bump in price will trigger some additional production that you'll see in 2019 and 2020.

What happens in the low cases is that as costs are very -- our costs are high in the low-demand case, production is not going to grow as fast.

So, this -- excuse me. So, this slide does a little bit of a comparison with our results and the EIA reference case. You know, there's going to be a presentation from them later today. But, so -- but the graph on the left, you can see a comparison between our forecast for the year 2020, 2025, and 2030. So, if you look at 2020, we're 5 cents off. I mean, if you look at the spreadsheet that was used to build this is -- they're a little bit higher by 5 cents. But, however, after 2020, you can see that they are forecasting more production, more growth in production than we are, that staff is forecasting at this time, and also -- so, what's happening is that, since they're showing more supply in the market, that's going to slow down the growth in their prices.

And, again, in -- one of the things we want to update going forward between now and when we produce the next results is look at potential supplies and the cost of producing those and see how much they changed from a couple of years ago.

The next few slides are going to be pertaining to the California market. So -- and we'll get more into this in the future slides. But what is basically happening here is that, if you look at starting in 2016, that prices are -- prices are fairly close between the Malin, Oregon, point. Where -- that's a point where gas imports come into California from Canada and the Rockies.

And, then, in Southern California, there's the Topock, which is in Arizona, and the other side of that is in Needles, California, off of Interstate 40.

So, what you'll see over time is that what the model is showing is that prices are going to go up. The red line here is Topock, but those prices are going to go up at a faster rate than the prices at Malin.

One of the things that the model is showing is that production in Alberta, Canada, is going to increase, which means -- and we'll see this in a later slide -- is that we're going to -- there's going to be a growth in shipments of Canadian gas to California.

In the southwest, what is happening is we are seeing some slowdown in production in the San Juan Basin. However, the real story in the southwest is that there is expected to be a greater demand in Mexico for gas produced in the southwest. And this includes -- some of that gas is going to get to Mexico by -- there's going to be gas being pulled off the El Paso Line in Texas, New Mexico, and Arizona going to Mexico. So, what happens there is that that supplier there now has the option of, well, I'm going to sell it to Mexico or sell it to California, which will push prices up.

So, in looking at California's gas demand, what's suppressing the California natural gas demand are implementation of additional renewable generation for California, also increased energy efficiency, which is going to reduce -- the energy efficiency will reduce overall electricity demand, which will also put -- pours down natural gas demand. So -- but if you look at the graph here, that even in the mid case, 13 years from now, we're going to use less gas than what we used in 2016.

And what's really -- and, then, going to the power generation sector, so if you look until 2024, you'll see a steady decrease in natural gas demand in all cases. But what happens is, is there is going to be an uptick after 2025, because that's when we assume that the Diablo Canyon shutdown will occur, and a lot of generation could be met by natural gas and that will -- and that you could see past 2025 and after, the demand for natural gas increases.

So, earlier, I talked about -- so, one of the things that this model could tell us is how much gas are we getting from what's being produced in California compared to if we got it from other states or other countries.

So, if you look at -- so, on the left-hand side here, you'll see California demand for 2016 and then what's estimated for 2026. And then the pie charts below show shares of where that gas is coming from. So, there is production of natural gas in California that meets about 11 percent of our demand, and that production is going to drop within the next 10 years. There are -- there are potential reserves of natural gas in California; but I think due to the state's policies that it's very unlikely that that is going to be developed.

So -- but what's also happening, as the share of California-produced gas goes down, our model is also showing that we are going to be importing more gas through the Malin Hub through Oregon and into Northern California. And, earlier, I talked about how we expect that the prices in Alberta are not going to go up as much. And we do expect some increase in production there. So, what's going to happen is that California will likely rely more on gas produced in Canada.

And, then, also, you can see here that, as I talked about earlier, our reliance on gas from the southwest will decline over the next decade as well, as those prices climb and there's more competition for that gas with Mexico.

So, the next slide builds upon this last slide, and it now goes through, you know, what's the supply portfolio going to look like in low-, mid-, and high-demand cases.

As you can see, the California production is going to be -- which is the purple slice here -- is going to be constant. But what's happening here as we move from the low case on the right to the high case on the left is that as -- the high-demand case we're getting a higher percentage of the gas from the southwest, which makes sense because what the model is going to do is it's going to, you know, start acquiring the cheaper resources first and, you know, get the lower hanging fruit, if you will.

But what's also happening within here is, yes, we can get gas from the Rocky Mountains and from Canada through the Malin hub. But, over time, the gas from Canada is going to be a higher percentage of what goes through there.

So, here are the conclusions of our model. So, we're showing that, throughout the United States, natural gas demand is going to grow at an annual rate of about 0.7 percent per year between 2017 and 2030. But, on the other hand, the implementation of renewables, energy efficiency in California will suppress California's natural gas demand over that period. But, however, there is a slight rebound due to the shutting down of the Diablo Canyon.

Our results show that prices, Henry Hub prices are going to grow by about 2.6 percent per year. And that's going to be driven by some growth in demand and also the need to produce from resources that aren't developed at this time.

However, so -- but our production growth is at an -- is also at a slower growth than demand growth, which is also the reason why prices are going to pick up.

California does produce its own gas, but it will produce a lower percentage of that over the next decade. And we will see our model shows a greater reliance from -- on Canadian gas and also -- however, if we go from the low-, to the high-demand case, we're more likely to procure more expensive gas from the southwest.

The next steps, I tried to summarize them. I think there's a lot of them that we need to look at, but I'll go through these.

Again, updating information on technically recoverable resources, we'd like to get something more up to date. What we've used here mainly comes from -- is mainly what we used in the last runs in 2015. We'd like to use more up-to-date information. And that's -- that is the most important input into this model because, looking ahead, those costs of developing what's available and when they get developed and how much of them get developed is going to -- I mean, really is what makes the difference in prices looking ahead.

Another thing that we'd like to do is get a better handle on international market developments, particularly as the United States within the next couple of years is going to become a net exporter of natural gas. So, what mainly drives that is LNG exports, particularly in the Gulf Coast. And, also, there's a liquefaction portion that's going into the Cove Point facility in Maryland. So, there's going to be this -- there's this whole other burgeoning world market for natural gas and for American natural gas. And we want to better understand that. And if you look at -- for instance, if you look at EIA's forecast, that's really what's going to push us over the edge in terms of being -- the United States being a net exporter.

So, although, that -- although those exporting activities are going to come out of the Gulf Mexico and the East Coast, the demand for that gas could push up prices here for us, as California is connected to that North American soon-to-be more internationalized market.

One thing that this presentation has touched on is an expected growth in demand for natural gas in Mexico. In Mexico, they've done some restructuring of their natural gas market. And what they hope to do is to do some fuel switching within their industrial and power plant fleets to move from oil to natural gas, but also attract more international investment. And what that international investment is in the form of are additional pipelines.

So, in the model, one of the ways that we've updated this from two years ago was we've added more infrastructure that has the ability to deliver gas to Mexico, but we want to get a better handle on what is in Mexico that transports that gas within the country. And one of the resources that we are using I saw in the BP slide that they're going to present later today.

Another -- so, within the next couple of months, the Preliminary California Energy Demand Forecast will be coming out. And, so, we would incorporate those as well, and that includes the transportation sector as well. And we hope to have our next set of results in time for our next workshop, which has already been scheduled on Wednesday, September 20th.

So, over the remainder of the spring and the summer, we will make these modifications and upgrades to the model.

And I will be glad to take questions and comments.

CHAIR WEISENMILLER: Thanks. Thanks for really digging into this and working through stuff.

I guess the one area I really wanted to focus on is, you have the assumption that electric generation load will go up after Diablo Canyon is shut down. PG&E has committed in its settlement that that will not happen, you know.

And, so, what we need to understand then is exactly what they're anticipating. Again, that will not happen under the terms of the settlement which the PUC approved. So, one, is I'd like to get is a better sense of the -- and I think the general expectation is, again, coming partially from yesterday's workshop, is that EG, electric -- you know, gas demand in California will keep dropping pretty precipitously between now and 2030.

So, given that, I think one of the things that we want to focus on is to get from the PG&E, Edison, and SDG&E their projections of EG demand in that period of time. And, certainly, the CAISO has out some. Their was their regional study, you know, would -- assuming, again, at this point, the base case what they're seeing as long-term projections or any updates on that. I guess one is that might us, too. So, we need that. When we get to submitting comments, we need that submitted.

We're going to need those submittals from the utilities, and it may help in terms of getting from -- in terms of the CalGas report getting the EG loads broken out from the rest of the noncore, so then we can calibrate there better.

MR. ORTA: And, just to clarify, and that's one of the -- when we do our next set of model runs, it will include updated estimates on electricity, which will incorporate the future electricity demand estimate, which also means that those will be used for another electric dispatch model run as well. So, we plan to incorporate that, and we look forward to, you know, that and also what the utilities' perspective is in the next 13 years or so.

CHAIR WEISENMILLER: No, that will be good. I think just we need to circle around on that assumption, get the best estimates from others, and then when we get to the 20th, we can have better analysis there.

MR. ORTA: Okay. Thank you.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Thank you, Jason.

Next, I'd like to invite Michael Thomas from BP Energy to come and speak.

MR. THOMAS: Thank you very much for having me today. I'm Michael Thomas. I'm the Chief Operating Officer for BP's North American Natural Gas Marketing and

Origination Business as well as Operations.

Today, I'd like to talk a little bit about BP, my organization, what we're doing from a renewables perspective, and then talk about the U.S. Gas Fundamentals from a supply-and-demand perspective and what the potential is for the pricing forecast, which I think Jason covered quite a bit, so I'll try to weave in as much as possible into what he talked about.

So, as always, we always put a disclaimer here to make sure I'm not providing any advice. Anything that I say, that's particularly enlightening, I probably can't take credit for it because I have a bunch of analysts that put together these presentations for me.

So, just on BP in the U.S. You see that we've invested over $90 billion in the U.S. over the last 10 years.

BP's generated $80 billion in economic value in the U.S. in 2015, and we'll have the updated 2016 numbers.

But while a business is supposed to create economic value, that's not all of who we are. You see at the bottom left there safety is our number one priority in everything we do, in our people, our processes and our -- if you track BP's safety metrics over the last several years, we've seen significant improvement there. We supported over 145,000 jobs across the United States.

And then one I'm particularly proud of is we've invested 147 million in U.S. community programs. And I did look up for California, about 10 percent of that 147 million is donated to the California communities.

This next one is -- so give a little bit of background on who I am. So, I've been with BP 11 years. I ran the Risk Organization for several years. I ran the North American Power Business Marketing and Trading for three years. And I went over to London in 2013, spent six months running the global LNG business, as well as the European Gas and Power Business. And for the last four years, I've been running this business that you see up on the slide here.

So, BP is the largest gas marketer in North America. We market between 22 to 25 Bcf a day. If you look at our -- a little bit of overlap there, huh? If you look at our upstream business, we produce about one-and-a-half Bcf a day. So, you can see that we deal with a lot of third parties. We're active in every mayor producing basin.

All of these green dots are all of the different offices that we have. And you can see Irvine, California; we have an office there. But across all of North America, Houston being our headquarters, Calgary being the second biggest office. And then, in each one of these offices, they mainly deal on the consumer side of the business, so we interact with over 3,000 customers on a daily basis or weekly basis in supplying them their natural gas. We move about ten Bcf a day of natural gas. And we operate on 235 different pipelines and utilities. So, we span the entire area.

And then you'll see -- you know, Jason was talking about Mexico. We recently just put in a Mexico office. With deregulation down there, with the growth in natural gas, we're getting active there, as well as our upstream and our downstream businesses is participating there.

Next, I just wanted to touch on BP and renewables. So, we've definitely committed to a low-carbon future. BP's renewable business is the largest out of any of the oil and gas majors. We've got a significant wind business. We're top ten as far as wind generation. We've got a large biofuels business in Brazil that creates ethanol off of sugarcane. And, then, we've also been building up a significant business dealing in the LCFS and the RINS market.

So, if you look at that last slide, you see all of those different offices there -- and I just talked about all of the different movement of gas that we have -- it created a perfect opportunity. Our guys in the -- our guys and gals in the Irvine office and Salt Lake office started to look at the EPA Regulations, the California Regulations, and said, We need to go out there and we need to find landfills, anaerobic digesters, wastewater treatment plants all across North America. And, so, with all of these different offices -- so the Toronto office, in particular -- we started to work with a couple of different landfill sites there. And, then, in Indianapolis, there's CNG and LNG facilities. And we were able to connect the dots. And, obviously, in California a big need from the transport sector.

So, we were able to basically leverage our scope and scale to be able to participate in the biogas business. We are an Obligated Party under the EPA and the LCFS; so, obviously, we have a vested interest in being able to create these projects, as well as there's a lot of third parties out there that we work with to be able to sell them the RINS and LCFS that are generated off of this project.

You can see the stats there: Over 300,000 LCFS; 130 million renewable identification numbers; 15 pathways; and 80 fueling stations. And that's recently almost doubled. So, over, I guess, a month ago we purchased Clean Energy's upstream renewables gas business. So, you can see the commitment we have to the California program, as well as to the EPA program, to be able to find projects to be able to generate these.

So, I'm not going to a spend a lot of time on all of the fundamentals that are driving North American gas markets. This is just animated to show rig counts, storage levels, oil production, U.S. generation by fuel.

I'm going to try to hone in on gas supply, Mexico, the global LNG market, and then wrap it up with a little bit of power.

So, the U.S. gas supply outlook -- Jason was talking about this -- I went back to 2011. I think it's a pretty interesting story to look at.

Over the last five years, we've increased our supply by 20 percent. You can see that the winter of '15, '16 we plateaued. We lost over a Tcf of gas demand across North America that winter. February 26th, I think natural gas hit $1.64. You started to see rigs come off significantly with prices at that level. And, so, you saw production continue to fall up through the winter of this year.

And, then, you could see that the range of forecast shows significant growth over the next two years. Surprisingly, the range of forecast is 10 to 20 percent. So, you're talking about over a-year-and-a-half period growing by the same amount that it took to grow over that five-year period.

Two big factors there. One is the northeast infrastructure. So, there's a tremendous amount of gas supply up there that is currently constrained because they don't have the pipelines to get it to the Midwest, to get it to the southeast. And, so, we're seeing a lot of pipelines come online over the next year, which is going to increase their price. So, Henry Hub is trading at $3. They're getting $2 or $1.80 for their gas in the basin. They'll be able to get it out to Chicago, to Michigan, to the Gulf Coast. The other big factor in growth is with oil prices above $50. The Permian Basin, what you're seeing, a tremendous amount of rigs. From an oil perspective, it's the lowest cost supply basin in everybody's mind. So, you're seeing a lot of oil rigs there, and there is a lot associated gas in that basin. And, so, you're seeing a lot of production growth from the Permian, as well as if the northeast de-bottlenecks, I think you're going to see quite a bit of growth there.

Actually, going back there. One of the interesting things, just since we deal with so many different producers, that I've seen, the CFOs will come in and talk about their financial projections. And I think historically, you know, they would be able to give an idea three to five years out what their production levels would be. What surprised me over the past several months is now they're coming out with potentially 30-, or 40-year projections. They're saying that with these, let's say, two counties that I have in particular in Pennsylvania, I could run two-and-a-half rigs and I could produce the same -- let's say 2 Bcf of gas, I could produce that same 2 Bcf of gas for the next 30 to 40 years. They said, if we could get the bottleneck, then I can run four-and-a-half rigs, I can produce four-and-a-half to 5 Bcf a day over the next 30 to 40 years. So, I think that's really transformational as far as what you're seeing with the, I guess, the more process-driven rather than having to innovate all the time to figure out where natural gas is.

But I think some of the producers have gotten some -- very clear on where those sweet spots are in the basins and have the technology and the capability that now they're projecting out a lot longer than what we've ever seen before.

So, on the demand side, Jason talked about the growth. So, this chart over here shows that we've tripled gas consumption in Mexico over the last five years. We've put down here the infrastructure that's been added in. If you see these pipelines, NET Mexico, Los Ramones -- NET Mex they call it -- when it's in service basically got quite a bit of gas coming in. You had two other lines just come on, the Trans-Pecos and Comanche, so another two-and-a-half

Bcf. And then you have another 3 Bcf coming online over the next several years.

So, really, the drivers there is when I showed the LNG slide and I showed the international prices, Mexico has seen a significant decrease in production, native production, and they were importing a tremendous amount of LNG. Back in 2013, 2014, they were importing at $12, $15, $17. And they're looking north of Mexico looking at all the natural gas production in the U.S. saying, Why don't we just build pipes in here? We'll be able to save a significant amount of money versus the international prices. And they're trying to do the same thing as the U.S. from a clean energy perspective. They're trying to retire coal, retire oil plants. You're seeing quite a bit of industrial expansion down there, as well as the deregulation going on where they feel like they'll be able to participate with the BPs, Shells and other companies to have a competitive market right now and not be captive to Pemex.

So, this was what I was referencing on the LNG slide here. So, to orient everyone, the orange line is the JKM. So, that's the Japanese Korean marker. It's a simplistic way of just thinking about what Asian LNG prices are. NBP is the Northern Balancing Point. So, it's a pretty good proxy for European natural gas prices. And then you have Henry Hub at the bottom there.

And you'll see that, while you took those two, if you took Europe and Asia off there, it would look like some decent volatility in the Henry Hub price. But when you look at Europe and Asian prices, it's pretty staggering.

I was there in 2013 when we saw these spikes. And it says it was below $20, but I know there were some cargoes that were selling for $22 to $23 for MMBtu. So, thinking about Henry Hub at $3 now versus having to buy gas at $20.

A big driver there was Fukushima, was the tsunami in Japan that shut down the nuclear facilities, as well as in Brazil, I think they're about 80 percent hydro, they had a significant drought and were required to import LNG cargo. So, South America had a lot of demand at the same time as the Asian markets.

This also sent a price signal to the United States. So, if you could buy $4, $3.50 gas and could you sell it for $12 to $20, that would be a pretty good reason to go ahead and put in liquefaction facilities.

You could see what's happened, though, recently is that we have Asian and European prices that are trading $5 to $5.50, and you got Henley Hub at $3, so not as much incentive. So, you say, well, you know, if we haven't built these LNG facilities, let's just go ahead and stop it. But this shows over here all the LNG that's going to be coming online.

The owners of the LNG liquidation facilities have sold off the capacity to Japanese utilities, European utilities, BPs, other people. So, they have a vested interest in completing the infrastructure. And, really, the risk of whether or not these facilities make money they've passed off to third parties.

We already -- you know, this is -- we're already seeing exports. So, Sabine Pass, this text up here, is currently flowing around 2.3 Bcf a day. They've got three trains online, an expectation that they'll have another one or two trains on.

Jason talked about Cove Point is now going to be exporting. And then you could see that 2018, a significant amount come on, and then 2019 to get us to the 9 bcf.

So, yes, I think the real wild card over the next several years is, if you don't see this price spread increase significantly, you may not see all of these facilities operating. It's similar to in 2008 when we thought we would run out of gas and we put all the re-gas facilities in, we ended up not using hardly any of them. You run the same risk with the liquidation facilities. I think the only problem is they cost probably 20 to 50 times more. So, there's tens of billions of dollars that are going into these facilities, and unless the -- unless spreads wide and you can end up with a situation where you don't see a high utilization factor for these LNG terminals.

To put it in perspective on the -- so, this is the U.S. LNG export. From our 2035 outlook, we've put the LNG growth across the world, our expectations from 2015 to 2030, 2015, 2016. The big drivers of LNG supply -- you see the United States there in green. Historically, we have not been an exporter except for a little bit in Japan. You see Australia is now a big participant. And that's one of the reasons why these spreads have collapsed so much. From the confluence of events, all of a sudden you have Australia coming online at the same time that you see the United States coming online. So, a huge amount of supply coming into the market.

You need some structural changes from a demand perspective to be able to take in all of this LNG. And, so, it will be interesting to see. There may be a bit of lag, but over the longer term, we do expect the LNG market to grow from 30 to 80 Bcf over the next 20 years or so.

And then where we think the demand will come in, ultimately, Asia. I think you could take any commodity and you could put Asia in there. But there is the expectation that China, India is where you're going to see a lot of the

LNG demand. And, then, in the European market, we are seeing a drop in production there, so we do expect to see them importing some.

So that was specific to the LNG markets. This looks at the global gas demand. They said it went from 30 -- from 30 to 80 Bcf, but you can see that on the right side there total demand internationally is just shy of 500 Bcf by 2035. So, LNG market is still a small percentage of the overall international market.

Projections for us is that gas grows by 30 percent over this time period. Where we think the big supply growth is, the U.S. from a shale perspective, it's over 40 Bcf a day of incremental growth. That would double the size of the shale that we currently have. We don't have a patent on the technology, so you do over this time period start to see China and Africa start to have shale and then other areas, Europe, you start to see some additional supply growth.

With that over that time period, you see some decline and then conventional growth comes out of your traditional areas, the Middle East, Russia, and then Australia, as we showed with the LNG that's more conventional growth that's expected there.

And, then, where is it going to be consumed? The power generation space, I got a slide here in a minute that shows the coal retirement expectations, industrial expansion across the globe increases as well. That's where I think that the majority of the supply will be soaked up in that time period.

So, if you look at the power markets, I just put up here four different regional areas. PJM, the Northeast, you can see the brown. A significant amount of coal retirements over that time, and they're really looking at natural gas to be able to fill in along with a little bit of wind and solar. So, expectations in the east that you're going to see demand growth from natural gas in the power generation sector.

ERCOT, a lot of the coal retirements have already happened. Expect to see a lot more wind over the next several years, as well as gas being a key contributor, and then the solar.

And then, MISO, Midwest, seeing quite a bit of coal retirements. Their plan is to fill that in mainly with wind, as well as some -- putting a little bit of gas in over the next couple of years, to get some coal retirements during that time and some gas facilities coming online to manage the base load.

And, then, the market that we were talking about with Jason in the California and the west, see a significant amount of solar coming in, very little natural gas, some coal retirements over that time period. But the dominant story being the solar market. And just a couple of graphs showing California installed solar capacity and distributed solar capacity and just the parabolic move up in the -- thank you -- in the solar capacity. And, then, which I think everybody is familiar with, the duct shaped for the power market. So, while, you know, we understand from a base-load perspective, natural gas won't be as big a factor in the California and the west markets, with the sharp changes in the curve, you know, needing to ramp up 10-, to 13,000 megawatts in two to three hours, still believe that natural gas can be a flexible resource to support the California markets.

And, then, the long-term Henry Hub spot price. Jason talked about this. I'm sheer EIA will talk about it as well. I think Jason was talking about that he's at a higher end than what is expected from an EIA perspective.

The black line is the NYMEX forward. You could see that even with production coming on, the LNG facilities, the Mexico facilities, the power gen, there's really a perspective in the marketplace with the forward curve that there's ample supply right now, a perspective that prices will tail off over time. But the range of outlooks, you know, you guys expecting higher prices, a lot of it depends on the global market. As Jason rightly said, our analysts are all about the international market now, that if you don't understand the international market, you're no longer going to understand the North America market.

So, we have to understand all the factors that we talked about with the LNG to then understand, you know, where we believe prices will go.

We have seen -- like I said, I have over 3,000 customers, consumers. A lot of concern from them that prices will go up from where the curve is right now. If you looked at the five-year average price, it's around $3, slightly below $3. It's only been at this level three times in the last 17 years that you would be able to buy at that price. So, we are seeing a lot of consumers come out and hedge out five to seven years to protect themselves from upward risk in price.

So, key insights. The North American market works: Prices work to balance supply and demand. You see that that first animation, all the different factors that go into it. You know, two years ago, we had no winter, you were able to take a lot of the coal generation and switch it to natural gas generation and soak up a lot of the marketplace. So, we've got a tremendous amount of flexibility in North America right now. And I think that will be a big factor as to whether or not our LNG operates at a high capacity. I think some other regions, like Australia, where they're going to have all this LNG, they don't have a domestic market attached to it, so if you they don't export it, they have to basically leave it in the ground, shut their facilities down, and you could have all kinds of operating risk associated with that. So, I think because we're such a big complex market and have such great capabilities, we'll be able to help the global markets balance.

We talked about the longer-term factors. We shouldn't underestimate the importance that weather has. The last two winters, we've seen significantly warmer weather. Even with that, you know, we're also twice as expensive, this winter having almost as warm a winter. So, there's other factors beyond weather that are playing into it. A big part of that being supply dropping off when the rigs dropped off. But there is an expectation that supply is going to grow over the long term. As I talked about, those producers that now have the capability to project out 20 to 30 years, it's pretty phenomenal to think about that they're that comfortable with the technology and with the resources that they have.

We talked about Mexico and LNG are really going to be key demand drivers in the medium- to long-term. Pricing relationships will continue to evolve. Like I said, risk management, we're seeing a lot of people take action to mitigate any upside risk. And, then you know, it's our belief natural gas is going to be an important part of the future power generation and transportation fuel mix in our own traditional business, as well as our significant investment in the renewable natural gas business.

So, I think I rambled on probably long enough there, and we can open up for any questions.

CHAIR WEISENMILLER: No. Thank you. Just a couple.

What's your expectation for the level of growth for renewable gas, particularly in the transportation sector, over the next five years or so?

MR. THOMAS: I don't have the -- I don't have the particular number. I think what we've been constrained with is on the supply side, so finding enough landfills, anaerobic digesters, and then helping them to get financing. So, what I talked about was we have all the infrastructure to help get their gas to the market, but what a lot of them are struggling with is getting financing. And, so, BP has come in and we'll say, Well we'll buy it at a fixed price for a period of time, or, We'll try and help you with your balance sheet to be able to get financing.

So, we haven't really seen, from a renewable natural gas perspective, any limitations on the transport sector. It's really just getting enough renewable natural gas to then feed into those markets, otherwise, they're just going to be using traditional natural gas. And I could get the numbers for you, but I don't have them in front of me, just the transportation sector.

CHAIR WEISENMILLER: So it would be good to see that.

Also, I wanted to ask, I know -- I met with the NDRC. They were very interested in, you know, basically increasing their natural gas and, you know, the shale gas. And I see you have a piece there, right? My impression was that they had not been that successful so far. What's your sense of status of shale gas production in China?

MR. THOMAS: I know we just formed a partnership with one of the Chinese entities to develop shale gas. I think you're right. I think people underestimate the amount of infrastructure that we have in the United States: The water, the sand, the pipelines. And, so, you may have shale available, but if it's in a remote location, it's going to be very difficult to take advantage of it.

And, so, I think that they're still trying to solve all that. I think our projection is, over the next 20 years, they're going to solve that. So, over the shorter term, they've under-delivered on all of their estimates that they had thought they would get in. But over the longer term, the expectation is that they'll be able to solve that to some degree.

CHAIR WEISENMILLER: Okay. Now, the -- that sounds reasonable.

What's your sense of how much higher demand would have been last winter in a more normal winter piece of weather?

MR. THOMAS: 2015/'16, I think we under-burned by 750,000. The winter before, I think was over Tcf. So, going into probably the middle of February, we were warmer than the prior winter.

CHAIR WEISENMILLER: Yup.

MR. THOMAS: But then we did turn cold for a period of time, so we ended up burning more gas than what we had the previous winter. So, just probably 750 Bcf versus the Tcf the previous winter.

CHAIR WEISENMILLER: Okay. Thanks.

COMMISSIONER MCALLISTER: I was late and you probably talked about everything I'm going to ask about, but sorry for coming in the middle. But I don't see it really in the presentation, so I wanted to ask. You know, I've heard sort of on and off that one of the barriers to RNG and getting more of it is clean-up requirements to make sure that it's injectable into the grid. And I guess I would like to get your perspective on that, how much of a barrier is that really and are there standards that are kind of more workable in the works or are already there.

MR. THOMAS: Yeah. I think in the pipeline tariffs, they have certain requirements. So, of the 15 projects that we've put in place, probably two of them have struggled with the technology to be able to clean up.

But that was a big concern for us several years ago when we were deciding to get into the RNG space was whether or not there would be contaminants or issues. And, so, the pipelines and utilities that the landfills or biodigesters are connecting to are very strict. And we'll test the gas significantly at the very beginning of the production.

So, I think the technology is there. Like I said, we have a couple of facilities that we're struggling a bit with now and won't let them go online until it gets cleaned up. But it does seem like people have figured it out and keeping it clean. And then it gets commingled into the utility system or the pipeline system.

But they're definitely testing it and not allowing any contaminants into their system. So, I think it's improved greatly over the last several years.

CHAIR WEISENMILLER: Thanks.

MR. THOMAS: Thank you.

MS. RAITT: Thank you very much.

And, so, we're going to mix up the agenda a little bit to have Anthony Dixon from the Energy Commission next.

MR. DIXON: All right. Good morning everyone. Excuse me. I'm Anthony Dixon with the Energy Commission. I will be presenting the Proposed Scope of our 2017 Natural Gas Outlook.

The outlook is part of the IEPR process and is produced every two years and it is required by the California Public Resources Code.

So, now, onto our sections that we are proposing.

Our first section is our NAMGas Modeling Results and efforts. Jason went into great detail about this, so there will be the write-up of that. We'll be talking about the development of the cases, the model itself, any price trends, flow trends, and supply. We will also go over the overview of the input and assumptions that were used in the model. And we will also be talking about understanding marketing uncertainty, what drives these prices in the market. Is it supply? Demand? Is it something else? We'll be really go over all those uncertainties.

Our next section will be Natural Gas Resources and Associated Issues. This will include a discussion of

U.S. and California production, especially the declining production in California. We will have a high-level overview of U.S. and California storage, reserves for U.S. and California, the proved potential resources, and also include Mexico's and Canada's resources. We'll have a discussion of hydraulic fracturing and its impacts on seismic activity and water quality. And some emerging technology, such as, methane hydrates or anything else we see that can really affect the market.

Our next section will be Natural Gas Demands in North America. This is a discussion of the total U.S. demand for natural gas and also power generation demand and how the growth of renewables is impacting this demand.

In our next section, will be the Development of Infrastructure in Imports and Exports in North America. We'll discuss pipeline changes, the developments and safety issues along with the pipelines, and also the infrastructure development in Canada and especially the infrastructure development in Mexico, and also the changing dynamic of LNG imports and exports.

The next section we would like to cover is Natural Gas Demand for the Power Generation Sector. This will be a discussion of the PLEXOS modeling efforts, how they develop their scenarios, our renewable portfolio, and also greenhouse gas price projections.

And then we would like to also have a section on discussing any Additional Emerging Issues and Areas of Interest that we have. This will include the new -- an additional methane leakage study that has come out, natural gas for use in the transportation sector, impacts of natural gas demand in the power generation sector due to varying hydroelectric generation. We've had some very wet winters and hydroelectric is up and we won't need as much natural gas for power generation, so we would like to really look to discuss that and go into that. And we really want to detail the pipeline and LNG exports, especially along the El Paso south line into Mexico because there's a lot of new development that will be drawing gas from those southern -- from the southwest into Mexico and it could really have an impact on California, especially in Southern California. Also, the declining production of natural gas in California. And a U.S. and California subsidence issues. And we would also like to discuss fuel switching in relation to zero net energy. And we will also touch a little bit on renewable gas, but it will be discussed in more detail in another IEPR chapter.

And some things we would also like to discuss and consider for future modeling efforts are whether events or extreme events, the well freeze off in the southwest and how it impacted our prices, the polar vortex to the northeast. Any of those things, a hurricane going through the Gulf Coast, how those can really affect our prices. We'd like to be able to start modeling those and really considering them. We would also like to have climate change be more input into our modeling at a national level. Scripps is developing a national heating and cooling degrade data set that we'd like to start using and modeling in our model. And also looking at natural gas liquids that are produced from the wet plays, such as ethane, propane, butane.

That there is kind of the overview of what we would like to discuss in our outlook.

CHAIR WEISENMILLER: Great. Thanks.

MATT COLDWELL: I'm going to channel -- do my best, at least, to channel Commissioner Scott, the Transportation Lead here.

So, on Slide 7 on the additional issues, you note the natural gas use in the transportation sector. Just curious, I don't know if this is a comment or a question, but is looking at electrification of the transportation sector from sort of the power generation point of view considered, or is it -- because it is an emerging issue, especially over the next several years?

MR. DIXON: Yeah, I agree.

We're more looking at the infrastructure need for natural gas because our modeling efforts look at how that's going to plug in the pipelines, what's it going to affect for supply, demand, the use of the pipelines, whether there are constraints. We're more looking at an infrastructure type of view, even though the electrical demand would be increased. So, our view is more of how is it going to hook in.

UNIDENTIFIED SPEAKER: Thank you.

CHAIR WEISENMILLER: I guess the one thing I was going to suggest adding, when you look at California's natural gas infrastructure, a lot of it came back in the era when we did the initial lines to the northwest and to the southwest. You know, the PG&E Line 300 system is sort of, you know -- usually go through their backbone. Some is pretty old. And, so, basically trying to get a sense of looking at the gas infrastructure and, you know, where -- what we need to worry about in terms of replacement over time. Again, pretty high-level summary of that.

So, as was struggling with gas system, obviously, on the one hand, we have to keep it absolutely rock-bottom safe; and on the other hand, figure out what its long-term future is. So, getting a sense of the distribution of the infrastructure and where we might have major new investments in 5 or 10 years would be good.

COMMISSIONER MCALLISTER: I guess just one comment. I think there's a lot of uncertainty around the ZNE or field sourcing generally in end use, and so I a lot of it depends on where the market goes and where rates go and things. And, so, I'll be interested in paying attention to that. That work going forward I think is kind of an interesting policy moment for that.

MR. DIXON: Okay. Thank you very much.

CHAIR WEISENMILLER: Yeah. And, again, one is I certainty really want to encourage BP, the utilities, all the other stakeholders to chime in in their written comments on areas we think we should try to focus on in terms of issues.

MR. DIXON: Thank you so much.

MS. RAITT: Okay. Well, we're quite a bit ahead of schedule, but I think we will need to take a break because of the availability of our speakers for this afternoon.

So, I would suggest we break until 1:00. That's kind of a long break, but --

CHAIR WEISENMILLER: That would be good.

MS. RAITT: Okay.

CHAIR WEISENMILLER: Okay. Thanks.

MS. RAITT: We'll be back at 1:00.

(Off the record at 12:15 p.m.)

(On the record at 1:15 p.m.)

MS. RAITT: Okay. So, we'll get started again.

Thanks everybody, welcome back to the IEPR Workshop on Natural Gas Scenarios. And we have -- our first speaker after the break is Kathryn Dyl from the Energy Information Administration and she will be presenting via WebEx.

MS. DYL: Hi. Hopefully, everyone can hear me okay.

MS. RAITT: Yeah, we can hear you loud and clear. Great. Perfect.

MS. DYL: Great. So, as Heather I believe mentioned, my name is Katie Dyl, and I'm one of the primary natural gas modelers for EIA in constructing the Annual Energy Outlook. And, so, what I was asked to do is give you a brief overview of the annual energy outlook as a whole and then focus on natural gas markets, specifically, production, prices, imports and exports, and potentially touch on electricity in California if we get the chance.

So, if you could go to the next slide, please.

The key takeaways from this year's Annual Energy Outlook are really that with strong domestic energy production in the United States, relatively flat demand, that leaves to the end result of the United States becoming a net energy exporter over the projection period in most cases.

And, that, you know, to give you the takeaway, I guess, early on, it is primarily not only because crude oil and product exports -- or imports, rather, are declining, but also with growth of natural gas exports.

In terms of crude oil production, just to touch on it, we see it rebounding from recent lows, but not growing, you know, considerably higher than the recent peak a couple of years ago.

On the other hand, across most cases, natural gas production continues to increase through 2040, and this is despite relatively low and stable natural gas prices.

So, what this means is that there's higher levels of domestic consumption driven primarily by the industrial sector and the electric sector, but also natural gas exports, specifically, liquefied natural gas exports.

But, as I'll show you in the later slides, these projections are very sensitive to the assumptions in the model, in particular, what sorts of estimates you make about resource and technology availability and costs.

So, finally, with modest demand growth in terms of electricity, what is really driving new generation is the retirement of coal plants, less efficient fossil fuel plants. And this is not only due to the Clean Power Plan, but also renewable tax credits in the near term and also the relatively low natural gas prices which tend to compete well with coal and still, you know, kind of keep natural gas as the primary fossil fuel for electric generation.

But, again, much like the above case, this generation mix is again sensitive to natural gas production and pricing.

If you could go to the next slide, please. And then one more. Thank you.

So, just, again, some outline for those of you that might not be familiar with the AEO. EIA generally has several cases, specifically, with different assumptions, low and high macroeconomic growth, low and high world oil prices, and low and high technology and resource estimates.

So, in terms of natural gas, the two big ones really are the world oil price and the resource and technology assumptions. So, just to give you a sense of what we mean in terms of high and low oil price, in the reference case, Brent crude is -- reaches about $109 per barrel in the reference case by 2040, whereas, the low price case is $43 per barrel at its peak. And the high oil price case reaches over $225 per barrel. So, quite high.

In the resource and technology cases, the way these are constructed is that there's not only a lower drilling cost and lower operating cost for rigs, but there's also higher estimated ultimate recovery from oil and gas wells. And, so, in the high resource and technology case, you get higher production at lower prices and, obviously, the other way around in the low oil and gas resource and technology cases.

Low and high economic growth, I'm not going to talk too much about that. You know, it's self-explanatory.

So, in addition to this, we also have a Clean Power Plan free -- or case, so no CPP, which you can take a look at and compare to the reference case as well. And, although all these graphics are going to be through 2040, if you're interested, this was the first AEO where we have results in model projections out to 2050.

Next, please.

So, on to the sort of big picture tickley (phonetic) results. Domestic energy consumption remains relatively flat; however, the mix of consumption is quite different. And this is led by a growth in natural gas consumption, which has the growth -- has the largest change over the projection, again, primarily due to industrial and electric power generation.

While natural gas has the largest sort of net growth, renewable energy, excluding hydroelectric power, actually has the fastest growth rate. And this is primarily due to the tax cuts -- or the -- I'm sorry, I'm missing the word -- arrearable tax credits through the early 2020s.

Next, please.

And, so, while in that last consumption graph we saw consumption remaining relatively steady, again, production increases led by dry natural gas.

So, by 2040, this actually results in natural gas being about 40 percent of total energy production in the United States. And, again, the crude oil and lease condensates do rebound, but stay relatively flat post-2020.

Coal continues to decline after a brief resurgence primarily due to regulatory environment. And, again, renewables are the primary benefactor of that growing considerably through the early 2020s and out through the projection.

Next, please.

Okay. And, so, moving on to the fact that we project the United States will become a net energy exporter in the reference case, this is due to, again, both the decrease in imports of crude oil and petroleum products, so, as you can see from the graph on the left, after reaching a peak in about 2005, total energy imports have been declining, and this is due to primarily decreases in crude oil and petrochemical product imports.

Exports, on the other hand, have been steadily rising since about the same time. And, so, we project about 2026 is when we'll reach the status of net exporter.

So, the graph on the right shows that breakout by fuel. And, again, it sort of makes clear that it's not only petroleum products declining, but also a large increase in natural gas exports, especially in the near term.

And, while in the past, it's been -- natural gas trade has been dominated by pipeline imports and exports from Canada and Mexico, LNG is expected to dominate natural gas trade, especially in post 2020.

Next, please.

And, so, just briefly to mention carbon dioxide emissions. We do project them to fall over the projection, but at a much slower rate than the recent past. So, from 2005 to 2016, Co2 emissions fell about 1.4 percent annually on average. And this, obviously, is due to the trend in the electric power sector, the switching over from coal to natural gas. So, in 2016, the transportation sector over took the electric power sector in terms of Co2 emissions, and we expect that to continue.

However, post-2016, we do see this moderating. And the annual average decrease in CO2 emissions is about 0.2 percent. So, again, much less. And I believe does not -- is not significant enough to meet the INDC or the Paris Climate deal standards. But I just wanted to briefly mention that.

Next slide, please.

And, so, finally, just to round out the general overview and assumptions for -- this is the reference case. We have U.S. population and GDP growing at historic rates or are consistent with historic growth rates, and energy intensity declining as the economy undergoes structural changes, and carbon intensity also continues to decline, but not -- or, yeah, carbon intensity continues to decline. And, again, that probably should -- that trend probably started around 2005.

So, if you could move forward, please, two slides.

Getting into natural gas. So, in terms of what resource types are contributing to -- or the resource types that we think are going to be responsible for the growth is shale gas and associated oil or associated gas from tight oil place.

So, in the chart on the left, rather, you can see that by 2040 we expect about two-thirds of total metric gas production to be from these two sources. And the reason we see this growth continue, again, despite relatively modest prices, which I'll show you in a couple of slides, is because we see new discoveries, new fields offsetting declines in existing fields. And, so, that's what, you know, allows this growth to perpetuate.

And, again -- or looking on the right, rather, we can see that in pretty much all cases, with one exception being the low oil and gas resource and technology case, again we see production continuing to grow. So, only in one case where we, you know, had significantly underestimated our resource base do we see production leveling out after 2020.

Next slide, please.

So, as -- while production, rather, continues to grow at a pretty safe clip throughout the projection, we see consumption growing but at a lower rate. And this is primarily due to increases in both the industrial and electric power sector.

So, in the industrial sector, we anticipate them to remain the largest consumer of natural gas throughout the projection and continuing to steadily increase, in part, due to petrochemical and other projects that are coming onboard in the next several years.

On the other hand, in the electric power sector, we actually see a modest decline in the near term through 2020, and that's due to competition from coal and also competition from renewables due to the aforementioned tax credits.

However, post-2020, we see natural gas

consumption again continuing to rise and -- yeah, continuing that trend through 2040.

Next slide, please.

So, the, again, large increases in production, modest increases in consumption results in fairly large changes in natural gas trade. And, so, in this graph, you can see that, historically, since, I believe it was 1959, when the TransCanada Pipeline opened, we have been net natural gas importer due to pipeline imports from Canada.

Additionally, LNG imports, which peaked around the mid-2000s, we see those tapering off and really just becoming occasional peak shaving source in New England.

On the other hand, as these imports continue to decline through the projection, we see exports rising. And this is true for pipeline exports to Canada and Mexico, as well as liquefied natural gas.

And, so, I guess dealing with Canada and Mexico -- or to address Canada and Mexico first. We expect the pipeline exports to eastern Canada tending to level off but averaging about a Bcf per day over the course of the year. And, despite this modest growth, we still think we're going to be a net importer from Canada.

Mexico, on the other hand, we see a lot of short-term growth due to Mexican energy reforms, specifically, building out of infrastructure, as well as reforming the electric sector, and the large build out of natural gas fire generation there. In our reference case or in the AEO 2017, we see these exports from Mexico tending to level off post-2020, and that's because we assumed that the aforementioned energy reforms in the petroleum sector start taking into effect and domestic production rebounds. However, that is a high unknown, and I believe the current state is that it's lagging a little bit behind. And, so, if anything, pipeline exports to Mexico could continue to grow and be higher than what we're projecting here.

And, then, finally -- oops, sorry. Just a -- it's okay.

Just a brief mention that LNG exports grow precipitously, or quite rapidly, through 2020, and that's due to, I believe, six or seven different FERC-filed LNG liquefaction terminals that are under construction that should all be operational by 2021. And, then, after that, we see modest continued growth in LNG exports.

Next, please.

So, moving on to what effect all of this has on prices, you can see that they vary quite widely, depending on the different assumptions, but really natural gas prices are bracketed by their resource and technology cases.

So, in the reference case, we see prices rebounding from around the $3 per MMBtu level in 2016, up to between $4 and $5 in 2020 for MMBtu. And that's due, not only to increased drilling activity, but also increased demand both from these LNG export facilities and industrial facilities coming online.

From 2020 to 2030, we see prices continuing to slowly rise to about $5 per MMBtu. And that's due to demand from the electric sector. But, past that, they really remain relatively steady at that level.

On the other hand, if in our high oil and gas resource and technology case prices remain below $4 per MMBtu throughout the projection. And, so, this -- these higher production levels at lower prices really drive added growth, not only in domestic consumption, but also exports.

And, then, finally, in the low oil and gas resource and technology case, prices actually near historic highs by 2040, and that suppresses both consumption and exports.

Next, slide.

So, finally, the sort of big unknown or the big -- or one of the big issues in natural gas markets and trying to anticipate what is going to happen with them is sort of what U.S. LNG exports levels we might expect or really how the LNG export market is going to evolve and really be shaped globally by, particularly, U.S. supplies that are coming into the market, Australian supplies coming into the market.

And, so, what we have here is the liquefied natural gas exports on the left-side case, and then accompanying that on the right, the oil-to-natural gas price ratio. And this really drives home the point that it's both world oil price and natural gas supply prices or Henry Hub prices that play a role in what sort of LNG export levels we might expect to see.

So, obviously, in the high oil price case, we actually see the highest levels of LNG exports. And this is due to the fact that, historically, and still today, the primary way to set up LNG export contracts is by inducting them to world oil price. And this is partly due to the fact that LNG substitutes for petroleum products, diesel and electric generation, and can be substituted as, you know, a fuel and industrial application as well with oil.

However, we do expect that as the LNG, global LNG market grows and more supplies move into the market that, instead of competing with oil, LNG will then be competing, you know, with other sources of LNG. And, so, that's when, you know, low domestic gas prices come in.

So, in the high oil and gas resource and technology case where we have the lowest natural gas prices in the U.S., we also see much higher LNG export levels than the reference case. Of course, on the flip side of that, when there's very low oil prices, LNG isn't a competitive or attractive fuel source for other countries. And when U.S. natural gas prices are high, our LNG exports aren't able to compete with, for example, Australia or other middle eastern countries like -- I believe Qatar is still the largest LNG exporter globally.

Next slide. And then one more over.

So, I'm not sure how much time I have left.

MS. RAITT: Oh, go ahead.

MS. DYL: Could you -- okay. So, I still have a couple of minutes?

MS. RAITT: Yeah, you're fine.

MS. DYL: Okay. Thanks.

So, in terms of our electricity modeling, in the AEO, we see that electricity use continues to increase but the rate of growth is fairly low, at least in the reference case. So, it, I think, averages a little under 1 percent per year on average through 2040.

So, if you could move to the next slide, please.

And, so, again, I believe I mentioned this earlier in the overview, but it's really not only laws and regulations but also, you know, natural gas price that drives what the generation mix might look like moving into the future.

And, so, in our reference case, we see that, despite the fact that natural gas overtook coal in 2015 and we expect it to still be a larger portion of the generation mix over the next couple of years, due to rising natural gas prices, coal, you know, again shortly overtakes natural gas as the leading electricity producer.

But post-2024 or 2025, natural gas, you know, again becomes the primary, or the largest, source of power generation and continues to grow throughout 2040. Again, renewables, we see that rise, and nuclear and petroleum remain flat. And, you know, non-consequential respectively.

However, for a comparison, looking to the right at the no Clean Power Plan case, we see a different story in terms of generation mix. So, in this case, we still have natural gas exceeding coal in terms of consumption by the electric power sector, but instead of happening in the mid-2020s, it happens in the mid-2030s.

And renewables, which overtook coal in 2030 in the reference case, never quite reach the generation share of coal without the Clean Power Plan.

Next slide, please.

And just to illustrate the role of natural gas prices, on the left is, again, the reference case with just coal, natural gas, and renewables. And the two graphs on the right show the projection in the low resource and technology case, whereas, the natural gas prices were highest and reached about $10 per MMBtu in 2040. And the low -- or the high oil and gas resource and technology case where prices remained I believe below $4 throughout the projection.

So, in one case, natural gas use actually declines and remains below both coal and renewables throughout the projection. And, in the other, natural gas doesn't see that sort of near-to-mid-term decrease in consumption and just continues growing its share.

So, the next slide.

I just wanted to add in because to touch a little bit on California specifically. And, so, the first caveat I'll make is that this is a bit of -- this might not be a completely apt comparison or -- in terms of the renewable part for California because in this case -- or in the AEO, rather, we consider hydroelectric power as a renewable energy source. And, additionally, some of the renewable energy sources here might not be -- might not actually be applicable for the renewable fuel standards. But I just wanted to show you what our power generation outlook is for California and make sure to point out -- or make sure to address that we do see California meeting its 50 percent renewable by 2030 commitment in the model. And I believe that's reached not only through, you know, renewable capacity in California, but also electric imports from adjacent states and regions.

And, if you have additional questions about this and I can't answer them, because, again, I'm tend to be natural gas, I can definitely direct you to who to go to for more information on that.

So, thank you, and I hope that -- you know, I hope that I addressed the issues that you guys wanted to learn more about today.

CHAIR WEISENMILLER: Yeah. This is Chair Weisenmiller.

Thank you for your presentation. Just a couple of questions. One was, I understand that your forecast of the market dynamic, I think what we've heard generally is that, say Mexico will be pulling gas out of the southwest away from California and that California will, you know, presumably be more reliant on Canadian or Rocky in that sort of market flow. Is that sort of similar to what you see?

MS. DYL: I think, actually, that in our projections we actually have a lot of natural gas supply coming out of west Texas from the Permian.

CHAIR WEISENMILLER: Uh-huh. Sure.

MS. DYL: And a lot of the infrastructure in

Mexico that's currently being built to send gas west is through Texas and over. And, so, I guess it really -- I don't know that we actually see larger draws from -- or larger imports from western Canada. We see those to continue to decline. I really think that in our case we see the production, particularly from west Texas, more than able to accommodate both growing Mexican demand and California.

But, again, with the caveat that we do have Mexican -- domestic production rebounding, whereas, if that doesn't happen and Mexican natural gas production continues its decline, that might change the results of it.

CHAIR WEISENMILLER: Okay. Thank you.

Other question is, what's your sort of projections of renewable gas?

MS. DYL: So, I don't believe that we have renewable gas contributing significantly to the generation mix. I would have to direct you probably to the electric team because we don't -- we wouldn't -- you know, I really couldn't hazard much of a guess on our side. The only thing I can tell you is that it really doesn't make a big difference in terms of productions on our side.

So, if Heather or Melissa want to get in touch with me if you would like the contact for somebody to ask that question specifically, I can do that.

CHAIR WEISENMILLER: Okay. That would be good.

Last question is just, in terms of the major growth in LNG exports, what do you see as the major market for that LNG?

MS. DYL: So, I guess the key to the answer is that, you know, we really don't -- in actuality, we really don't know where the LNG might go.

In our model, we have most of it -- most, if not all of it, going to Asia. But, again, we don't have South America as an option, and most of Sabine Pass's exports have gone to South America, at least in 2016.

So, I mean, I do think it's safe to say that most LNG is destined for Asian destinations, especially -- you know, there may be some going to Europe for, you know, energy diversity and, you know, some going to South America, but South American markets are very small compared to Japan, South Korea, and even growing markets like China and India.

It's probably not a terribly satisfying answer to your question, but, you know, I think it's safe to say that they're probably going to -- you know, if there's going to be a lot of LNG exports, they are probably going -- that means that Asia is demanding quite a bit of them.

CHAIR WEISENMILLER: Okay. No, that's good. Okay.

Well, thank you. Thank you very much.

MS. DYL: Yes, no, thank you for having me. And if there's any further follow-up questions, please don't hesitate to send me an e-mail.

CHAIR WEISENMILLER: Great. Thanks.

MS. DYL: Thank you. Bye-bye.

MS. RAITT: Okay. And thanks for your flexibility.

Our next speaker is Rose Marie Payan from Sempra Utilities.

(Off-the-record discussion regarding Ms. Payan's slide presentation.)

MS. PAYAN: Oh, the WebEx people. Oh, okay.

I would like to move around, but due to a request, I will stand here.

Greetings everybody. Thank you for inviting me to speak before you today. It's an honor.

My name is Rose Marie Payan, and I was the Statewide Coordinator for the 2016 California Gas Report.

-- the California Gas Report, as you know, is filed in compliance with the CPUC decision from 1995. And what it requires the respondent utilities to do is to prepare a full forecast in the even-numbered years and in the odd-numbered years we prepare a true up. So, this year we'll be putting out another report, which just has recording historical data updates.

And, so, let's get started.

Our model shows that new housing is the main driver for the residential forecast of growth, and employment growth is the main driver for the commercial industrial demand forecast.

From 2016 to 2035, the annual employment growth is forecasted to be about eight-tenths of a percent for Southern California gas area and 1.1 percent for San Diego County.

Our drivers for the economics come from global insight. What we will observe --

Yes. You still can't hear me? Oh. All right.

What we should observe is the next few years continual gradual recovery in the Southern California area of the new homes building growth and jobs also growth.

The next slide shows something very interesting. It shows the new home building for the time span from 1985 to 2035. And what you could see is the slump from the housing collapse after 2006. If you remember, the last recession began December 2007, and it lasted officially through the summer of 2009. And what this graph is showing is how the change in the composition of new housing has occurred since then.

Prior to 2006 and the crash that ensued, we see that most of the new housing starts with primarily coming from single-family homes. And then after that collapse and recovery, we see that the mix is shifted to multi-family housing. And, recently it's reverting back to an increase in single-family homes, but still we have a robust growth in multi-family housing structures.

The next slide shows our customer growth for Southern California service territory. We're expecting a five-tenths of a percent increase in new customers over the forecast horizon from 2016 to 2035. Our acoumeters from 2015 total 5.67 million customers.

The next slide shows our projection on natural gas prices. And they're very comparable to what the last speaker had showed us, the reference case; but what we're looking at is the 20-year low on natural gas prices. In constant dollars, we're expecting the gas price forecast to sit anywhere between $3 and $5.

And the way this forecast was prepared is in the initial years out to 2020, we used market prices, the fundamentals from NYMEX; and then post-2020, we used a blend of forecast prices from the CEC, PIRA, and Wood Mackenzie.

The SoCalGas demand forecast summary shows that we expect a decline in gas throughput averaging about six-tenths of a percent per year. Most of this is being generated from ambitious energy efficiency programs that more than offset modest meter growth and employment growth.

The total EG load, including cogeneration, is expected to decline an average of 1.1 percent annually from 288 Bcf in 2016 to 232 Bcf in 2035 mainly due to growth of renewable power and electric energy efficiency.

In our forecast across the various segments, we see growth predominantly only in natural gas vehicle market.

The next slide shows the graph, it's a visual of the different market segments that generate our total load across the years from 2015 to 2035. And it just shows the previous fact, which is, we expect a decline of about six-tenths of a percent per year.

For comparison purposes, we've noted the past CGR growth rate. The 2014 growth rate we had expected three-tenths of a percent decline over the forecast period. Prior to that, we'd expected a one-tenth of a percent decline over the forecast period. So, what you observe is the -- as the years go by and we have stricter goals on energy efficiency to meet, we see that we have more aggressive decline in the load. So, load is definitely expected to fall.

Okay. So, the next slide shows a summary of residential market facts.

The annual residential gas demand is expected to decline about five-tenths of a percent per year from 239 Bcf in 2015 to 218 Bcf in 2035. The decline in use for a meter more than offsets new meter growth. The reason for this again is attributed to energy efficiency programs, some conservation due to AMI as well.

Since 2001, weather normalized residential use per active meter has been dropping by about six-tenths of a percent per year.

And we've come a long way with energy efficiency standards. I came across some data recently before coming here, in 1980, the average use for a customer was somewhere in the 800 therms range. And, now, what we see, the last bullet there, single-family homes average 474 therms a year. That's quite a substantial decline. Multi-families' average use for customer is about 312 therms per year. And, again, this is adjusted for weather conditions.

The next slide shows the graph of the composition of the residential market.

This residential forecast was prepared with an end-use model. And what that does is it segments the market into meaningful portions of customer types. And, based on the data that are input for the typical customer, predicts out the load into the forecast horizon. And what we see is that most of the residential load consists of single-family usage. We have some usage being picked up by multi-family and the residual from master meter and sub-meter classes. But, in total, the residential demand is expected to decline five-tenths of a percent per year from 2015 to 2035.

Okay. The next slide shows the commercial demand forecast. The commercial demand forecast is broken out into core commercial and non-core commercial. And, as I mentioned before, the main driver for the commercial market is employment growth. And, even though we expect employment to grow over the forecast period, we do expect tighter energy efficiency standards, especially for the core commercial segment, be applied. So, as a result, the core commercial demand forecast is expected to average a decline of about 1 percent per year from 97 Bcf in 2015 to 80 Bcf in 2035.

The next slide shows SoCalGas' industrial demand forecast of industrial market has -- it's composed of core industrial, non-core industrial, non-refinery, and non-core industrial refinery segments. The industrial load is expected to decline six-tenths of a percent per year from 2015 to 2035.

Okay. So, the next slide shows a picture of cumulative energy efficiency savings or measures installed under the CPUC's EE program. And what's remarkable here is that most of the savings are projected to come from residential and core C&I sectors.

This CGR, when we prepared it, looked, in contrast, somewhat to the previous one because there were definitely much tighter standards imposed on the core commercial market in this round. But, all in all, the total savings are substantial and growing. And it's a pretty interesting picture of our reality.

The next slide shows SoCalGas, the gas-fired electric EG picture. And what it is showing is that the EG throughput for base hydro and dry hydro cases -- and, obviously, in dry hydro years, we have increased EG -- well, gas-fired EG demand. But there's also a projected decline over the forecast period.

The declining energy for electric markets is driven largely by the renewables consumptions and a lot of uncertainty.

Okay. So, what's happened? SB 350 was passed in October 2015. And what it requires is the state reach a 33 percent renewables portfolio by 2020 and 50 percent by 2030. Also, with energy efficiency, we're expected to achieve a doubling of the EE savings by 2030. Gas-fired generation capacity also has an uncertainty because of the fact that we have some thermal sources coming online and thermal sources being retired. But the net is a decline for both SoCalGas' service territory and also San Diego Gas and Electric service territory.

One of the assumptions that went into the model has to do with the once-through-cooling regulation. The forecast that was prepared for the 2016 CGR assumes the shutdown of those units for the forecast period.

Wholesale is the next market we're going to look at. SoCalGas provides wholesale transportation service to Sand Diego Gas and Electric, the City of Long Beach Gas and Oil Department, Southwest Gas Corporation, City of Vernon, and Ecogas in Mexico.

The wholesale load, excluding Sand Diego Gas and Electric, is expected to increase 3 Bcf from 2016 to 2035, from 25 Bcf to 28 Bcf. Sand Diego Gas and Electric's gas demand is forecasted to decrease an average of four-tenths of a percent. And we'll discuss those in the slides that follow.

As I mentioned earlier, NGV load is expected to expand, compared to the other market segments, it's a robust 3.3 percent per year. And this increase is driven mostly due to lower natural gas prices relative to gasoline and diesel, as well as some government incentives in that market.

Annual EOR steaming demand is forecasted remain flat at about 17 Bcf through the forecast period.

Okay. So, moving onto the San Diego summary. San Diego Gas and Electric's gas throughput is expected to decline six-tenths of a percent per year, relatively about the same rate as the SoCalGas service territory. San Diego Gas and Electric's decrease is mainly due to forecasted gas-fired EG load decline, which dropped an average of about 1.1 percent annually from 2015 to 2035.

The residential market is surprisingly showing an increase of about five-tenths of a percent per year. And, in contrast, the commercial industrial gas demand drops an average of seven-tenths of a percent annually as energy efficiency outpaces economic growth.

The next slide shows the growth in the customers from 2015 to 2035. We're expecting in this forecast period about 1.2 percent growth per year in new customers. In 2015, San Diego Gas and Electric's gas meters totaled 870,125.

Okay. The next slide shows San Diego Gas and Electric's demand to decline moderately from 126 Bcf in 2015 to 112 Bcf in 2035. And, as I mentioned before, that translates into about a six-tenths of a percent per year decline. Again, mainly due to declining EG loads.

So, Sand Diego Gas and Electric's residential market is expected to increase moderately, about five-tenths of a percent per year.

And this graph is composed also of the various different market segments that feed into the residential sector. For Sand Diego Gas and Electric, the residential sector consists of single-family, multi-family master meter and sub-meter groups. Predominantly driven the load by single-family usage.

The next slide shows San Diego Gas and Electric's commercial demand is expected to decline over the forecast horizon by about 2 Bcf.

Okay. The next slide shows San Diego Gas and Electric's industrial demand is expected to decline about 1 Bcf over the forecast horizon.

Okay. And then the next slide shows San Diego Gas and Electric's gas-fired EG is expected to decline. The total EG demand is expected to decline 1.1 percent per year from 72 Bcf in 2015 to 58 Bcf in 2535.

And then this slide shows San Diego Gas and Electric's energy efficiency goals. And the bulk of the core -- the bulk of the load savings are expected to be derived in core C&I programs. As you can see, the core C&I segment is the light blue area, and that's the majority of the energy savings, where they're coming from.

Okay. So, in conclusion, this slide next to the left slide shows the comparison of past CGRs with the last CGR for not only the Northern California service territory, but also the Southern California service territory; California statewide. The trend is pretty obvious. What it shows is that for Northern California, as well as Southern California, we're expecting an eight-tenths of a percent decline in the load. The trend is downward. For the state, we expect the load to decline almost 2 percent per year over the forecast horizon.

And it just seems that the reduction is just becoming more and more aggressive compared to the previous years, especially for Northern California because if you look at the first set of slumps that reflect the PG&E service territory, they had been expecting at least growth for the 2012 PGR and the 2014 forecast period and that turned south in this last forecast, in the 2016 CGR.

Okay. The summary slide. In conclusion, California's gas demand is projected to decline an average of 1.79 percent per year from 2016 to 2030. SoCalGas' end-use demand forecast is expected to decline 0.8 percent per year over the forecast period. The reasons for this decline are related to moderate customer growth, slow economic recovery, and renewed efforts on energy efficiency as well as the renewables target for 2030.

And the last bullet, energy efficiency programs will have a significant cumulative effect of reducing demand over the forecast period for the investor-owned utility.

The last slide is just a list of the CGR team and the participants.

Are there any questions?

CHAIR WEISENMILLER: Yes. Thanks for coming up and thanks for the presentation. I've got a few.

On your Slide 4, you show the residential growth in Southern California. I was sort of curious in terms of if your forecast is based upon differences within the area. And, if so, which parts of Southern California would you expect the most growth?

MS. PAYAN: Well, the forecast for the residential market is driven by an end-use model that has as an input the saturations from the WRATH (phonetic). And what it does is it segments the residential market into various different customer types: Single-family, multi-family, small and large, and then master meter and sub-meter. There is a meter forecast that feeds into that model, but it's not based on geography. It's just for the entire service territory. And what the end-use model does is it serves as a calculation to mimic customer choice.

The typical customer has as its choice, the ability to pick between different fuel types and different efficiency levels based on capital costs and operating costs and fuel prices as well. So, there's a simulation that underlies that end-use process.

CHAIR WEISENMILLER: And in that model, do you look at photovoltaics?

MS. PAYAN: Not to my knowledge.

CHAIR WEISENMILLER: Okay. I'm just trying to understand.

In terms of -- one, of which we talked a lot about this morning, was sort of the staff's forecast of electric generation load. And, so, one of the things obviously we're trying to do is sort of line up those between actually PG&E and the staff and also between you and the staff. So, one of the things -- and you've got sort of a decline overall. They tend to have more of an increase. So, I'm trying to pin that down.

One of the things that would help us if we could get sort of your CGR workpapers with the electric generation loads desegregated out of that.

MS. PAYAN: Our workpapers are posted online on the Southern California Gas Regulatory Website, as well as the San Diego Gas Regulatory Website. It shows the detail behind the construction of both of the forecasts for those to utilities, as well as, you know, the inputs.

CHAIR WEISENMILLER: The EG load broke out? Broken out?

MS. PAYAN: The EG load detail is presented there. But I believe -- I would have to -- well, subject to check on the detail, it may just be broken down on an annual basis.

CHAIR WEISENMILLER: Yeah. So, what basically we need you to do is work with the staff so that we can do the cross-comparisons and get on top of what is going on in the EG sector going forward. So that would be good.

The other question is you, unlike the staff and EIA, you tend to look at expected and then dry hydro. And, so, again, that would be something that would be good for us to understand that variation. We're trying to just -- obviously, this has been a dramatic year for us going from droughts to floods, so -- with presumably heavy impacts on EG.

MS. PAYAN: I could take that to our forecast -- our forecaster for the EG --

CHAIR WEISENMILLER: Right.

MS. PAYAN: -- market for more detail on the factors underlying the differences between the dry hydro in the base year.

CHAIR WEISENMILLER: Right.

Do you tend to look at differences in gas rate structures for EG?

MS. PAYAN: I'm not sure about that.

CHAIR WEISENMILLER: Okay. That's fine.

Again, that's something maybe the staff might want to follow-up on that one.

It's really interesting to see the declines you're projecting from the efficiency goals, particularly in the core commercial industrial sectors. Again, I think certainly as we continue to work on the quantification of energy efficiency and the doubling, you know, that I'm sure Andrew and Martha -- Commissioner McAllister and his staff -- want to follow-up with you on some of that.

MS. PAYAN: Oh, absolutely. We'll work with them and follow-up definitely. But, as you know, California is the leader in energy efficiency. I don't know where I read, but on the electric side, if you look at nationwide, the typical customer from 1980 to 2005, their EG usage increased about one-third. But if you look at California over that same period, it's pretty flat in California. So, it's quite a remarkable difference.

CHAIR WEISENMILLER: No. Definitely it's been a huge impact, you know, as we've gone to higher prices and more explicit energy efficiency, you know, on gas consumption.

Do you --it's probably somewhere else in the company, but in the CalGas report, do you look at renewable gas?

MS. PAYAN: Renewables, I don't believe so.

CHAIR WEISENMILLER: Okay. You know, we can follow-up elsewhere.

Okay. Again, thanks for coming up and thanks for your presentation.

MS. PAYAN: Thank you.

MS. RAITT: Thanks Rose Marie.

That concludes our presentations, and we can move on to public comment.

CHAIR WEISENMILLER: First is there any public comments from anyone in the room?

(No audible response.)

CHAIR WEISENMILLER: Let's go to anyone on the line. Any public comment?

(No audible response.)

MS. RAITT: We don't have any -- oh, we do have one.

CHAIR WEISENMILLER: We had that one question. If you want to --

MS. RAITT: There is one question I will read. Just one moment. Okay.

Why is the Henry Hub price forecast here different than EIA's Henry Hub forecast? That hub is outside California and affected by the wholesale continent. So why not just use the EIA's latest 2017 Henry Hub price forecast as an unmodified input into the demand gas model?

And that was a question after Jason Orta's presentation.

Okay. Jason is going to come up and try to address that question.

MR. ORTA: This is Jason Orta from the California Energy Commission.

In trying to answer the first part of that question, well, I explain in my presentation that compared to EIA, at least in the reference case, we're showing throughout the country a little bit more growth and demand, but particularly it's in the supply area. They're showing more production growth between now and 2030 than we are. But one -- in the presentation, one of the things that we are going to revisit for our next iteration of this is looking at updated numbers on potential resources and the costs of developing gas in those areas.

And to answer the second question of -- why are we doing this? Was that it?

Because, as I pointed out in the presentation, the model goes beyond price forecasts. One of the things that we try to get into are looking at where the long-term supply comes from, where supplies come from in the long term, mid-, to long-term. You know, because there's always -- in particular right now in the next -- you know, with the new administration, the question becomes, What is going to be our relationship in terms of trade with our neighbors? And, so, it's worth asking, at least in that realm, Where does our natural gas come from and what does it mean and also how does California fit into an internationalizing market for natural gas.

And I think, you know, that's why we do this analysis here is to show we're a part of this market and try to show how it affects us. And I think, you know, there were questions here about future demands in certain areas. As we pursue more energy efficiency and renewables, we have to look at the future of the electricity system.

MS. RAITT: Thanks, Jason.

And I neglected to mention that question was from Bill White.

So, thanks for that question.

Anything else?

I think that's it from WebEx.

CHAIR WEISENMILLER: Okay. So, this meeting is adjourned. Thanks again for everyone for your help today.

(Whereupon, the workshop adjourned.)

/ / /

/ / /

TRANSCRIBER'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 transcribed by me, a certified transcriber and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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

IN WITNESS WHEREOF, I have hereunto set my hand this 19th day of June 2017.

Kelly Farrell
Certified Shorthand Reporter
CSR No. 8081