DOCKETED

Docket Number:	15-IEPR-04
Project Title:	AB1257 Natural Gas Act Report
TN #:	203454
Document Title:	Transcript
Description:	AB 1257 Workshop on November 18, 2014
Filer:	Anthony Dixon
Organization:	California Energy Commission
Submitter Role:	Applicant
Submission Date:	12/16/2014 1:50:20 PM
Docketed Date:	12/16/2014

COMMITTEE HEARING

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

In the matter of,	)
	) Docket No. 15-IEPR-04
AB 1257 Staff Workshop on	)
California's Natural Gas	)
Infrastructure, Storage and	)
Supply	)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, NOVEMBER 18, 2014

9:05 A.M.

Reported By:

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P R O C E E D I N G S

NOVEMBER 18, 2014 9:05 A.M.

MR. BAUER: My name is Silas Bauer. I’m the Project Manager for the AB 1257 report.

CHAIRPERSON WEISENMILLER: Is your mic on?

MR. BAUER: It should be on. Yeah, I’ll just be a bit closer.

I’m the Project Manager for the AB 1257 report. What I’m going to talk about right now is just a quick overview of what the report is. And I apologize to any of you who have heard this before. This will be fairly quick.

But the whole point of today, and other workshops that we’re doing specifically for the purpose of gathering feedback for this report, is to get stakeholder input on how we’re approaching the report and what types of information we’re going to include in the report.

So, the purpose of the bill, this is a 2013 bill, and it tasks the CEC with identifying strategies to maximize the benefits obtained from natural gas, including biomethane as an energy source.

The way we’re approaching this is that we’re looking at a picture of how natural gas is used in California, currently, and trying to identify gaps in our knowledge. So, where are there areas that we need to learn more moving forward in the future?

The bill covers ten topic areas, which I'll get to in a second. It also requires us to coordinate with a number of other agencies that are listed here. And then it's due to the Legislature by November 1st, 2015.

The ten areas of focus, as you can see here, obviously today we're talking about infrastructure, supply and storage. We also look at transportation. Natural gas is part of the resource portfolio. And CHP.

We look at natural gas as a low-emission resource. And biogas. And then, also, we look at efficiency, zero net-energy buildings.

There are a number of cross-cutting topics, as well. We're looking at how natural gas and electric industries can implement said strategies. And the way to think about that is just, basically, how are the electric and natural gas industries using natural gas, now. Again, what are our gaps in knowledge?

And then we're looking at jobs development and State and Federal policy that's related to natural gas use in California.

And the last one, number ten, is very important. We're trying to gather all of the economic and environmental cost and benefit research related to these different areas of natural gas use. And we're looking to stakeholders to file that to the docket in this proceeding.

So, the way that these cost benefit analyses are defined are; authoritative, peer-reviewed and science-based analysis, or in consultation with the State Air Resources Board.

So, we're in constant contact with the ARB on a lot of these topics. And there's a lot of information on fugitive methane emissions, lifecycle greenhouse gas emissions and that's where we've been gathering the majority of this resource so far.

It's less common in some of the other topic areas, but if you know of something that you think should be included in the docket, please feel free to docket it.

The plan so far has been to run these workshops. We had an initial workshop on transportation, on June 23rd, and that was part of the 2014 IEPR update. The rest of the report is part of the 2015 IEPR. And so, you'll see that our docket number, now, is under the 2015 IEPR. We'll link back to the docket that we had for the transportation workshop.

The Supply Analysis Office had a CHP workshop, on July 14th, and that was a workshop that we sort of coopted together information about how natural gas is used for CHP.

Obviously, today, we're talking about infrastructure, storage and supply.

And then, early 2015, we'll have another workshop on efficiency. And then there will a summer 2015 workshop on our draft report, which will be published before that workshop. And we'll gather that feedback.

That will be a chance for people to log any -- or, you know, comment on or log any information on any topic within the report, so it's like a second workshop in each of these topic areas. That's one way to think about it.

And after that's done, we'll include all of those revisions sometime in the fall and get ready for our November 1st publish date.

Fugitive methane emissions. We're waiting for the studies that EDF is doing, and a number of other groups are completing, to be fully published before we have that workshop. So, it's probably looking like late summer 2015 when we'll have that workshop.

The reason we're doing that is we want to be able to get all of the PIs of these different studies to come and actually present their findings.

So, keep an eye out for that workshop, as well. That will be, I think, a very big one.

So, before putting this workshop together we had some conference calls with agencies, utilities, NGOs, just to get a sense of what we should be talking about today.

If you've looked at your agenda, you already know that these are the topics we're going to be discussing today.

Natural gas reliability and affordability in California. The southern system minimum flow issue. Natural gas/electricity coordination. And natural gas supply demand and production in California.

Again, I'll reiterate that we're not discussing methane leakage or pipeline safety today. As I have noted before, there will be a workshop for methane leakage in late summer of 2015, and pipeline safety, we'll probably gather all of that information from publicly available documents that are already out there, so this is pretty well covered.

Stakeholder participation. As I've said before, we encourage you to file comments. We have an e-filing system now. You'll find directions on the workshop notice how to e-file comments.

You can also step to the microphone today and put any comments that you have on the public record, and we welcome all of those comments.

Today is also going to serve as a Natural Gas Working Group meeting. That's typically been separate in the past. This time we're combining the two because the topics are somewhat similar.

At the end of the day, in the afternoon, there's going to be a chance for us to open up the discussion to any topic related to natural gas use in California, and that's specifically for the Natural Gas Working Group.

For most of the day, though, we're going to be sticking to the topics for this AB 1257 workshop.

And this is just information on how to submit comments. I'm going to leave this up so that people have it, if you want to take any notes on it.

I am turning it over to Chair Weisenmiller, who has joined us today, for any comments that he might have.

CHAIRPERSON WEISENMILLER: I wanted to thank the staff for organizing today's event and certainly thank all the participants.

This is certainly an important topic as we deal with -- you know, we've had a great increase in natural gas production and as a result, a decrease in price. Certainly, that's one of the national trends.

And at the same time, in California, as we deal with some of our other issues in terms of methane leakage safety we're trying to figure out, again, working through the topics under this legislation to come up with a solid report next year.

So, again, thanks for any information you can provide us on this topics so we can have a better record.

MR. BAUER: Thank you, Chair.

I'm going to move over, now, to a quick natural gas or California natural gas system overview, which will also be covered a little bit in presentations by PG&E and Sempra. And I'm going to leave some out, so as not to steal their thunder.

So, California gets its supply of gas from a number of different production basins throughout the country.

As you can see from this map, we get some from the Western Canadian Sedimentary Basin that comes down over the gas transmission, North GTN Pipeline, at Malin in Northern California.

There's also supply that comes across the new Ruby Pipeline, from the Rocky Mountain Basin, that delivers at that same Malin receipt point.

We also get gas in the south of the State from the San Juan Basin, and Anadarko Basin, and Permian Basin all in the southwest. And those are delivered over two El Paso Natural Gas Pipelines, the North Main Line and the South Main Line.

There's also gas that comes in over the Transwestern Pipeline, the Questar Southern Trails Pipeline, and the Kern River Gas Transmission Pipeline.

All of these pipelines deliver into either PG&E's gas system or Southern California, Sempra's Southern California Gas's system for delivery to different end-use sectors, cities in California.

So, this is just a slightly more complete view of the system. Upstream to downstream, upstream including production, so you have gas being produced out of reservoirs and basins, and transmitted on large transmission pipelines to processing plants. And then to either underground storage, California has a fair amount of underground storage.

And I should note that underground storage can either be a demander or a supplier, and that's essentially how it works. So, with the utility storage facilities, in the summertime there's a lot of injection, in the wintertime there's a lot withdrawal to provide supply when demand is high.

When you look at independent storage facilities, there's more injection and withdrawal throughout the year. Lots of marketers will store their gas there and then also use it in times of arbitrage.

So, gas moves from the transmission pipelines through the city gate, into the distribution system, and then to end-users, residential, commercial, industrial end-users. And then that's how it gets to your house, your business, or your facility.

Quickly, because this will be talked about later, PG&E's gas transmission system, as I noted, GTN delivers gas to the border of California and Oregon, up at Malin, and then it's transported on Line 400-401, the Redwood Path, down through Northern California.

And from this graphic you can see numerous compressor stations which facilitate that flow of gas.

From the south, the Baja path, which is Line 300 A and B, gets delivery form the EPNG North Main Line and Transwestern and Questar southern trails. And that delivers into the PG&E system from the south.

There's also one section, you can see sort of a jug handle through the Bay Area, that's also part of the backbone transmission. Then all the smaller pipelines are small transmission, local transmission.

So, PG&E can deliver over 5 Bcf per day.

The Sempra System, this is an important graphic because it will identify some of the things we're going to be talking about today. It's divided into a couple of different zones. And you'll see, of specific note, Northern Zone and Southern Zone.

The Southern Zone gets delivery from the EPNG, El Paso Natural Gas South Main Line. The Northern Zone, the pipelines that I mentioned before.

You do see one black pipeline on there that delivers between the two, but not a whole lot of gas. And so there is storage on the northern system, but there isn't on the southern system. And so that will -- that leads to some issues now, especially with SONGS no longer being online, that we're going to discuss today.

The other pipeline that you see in gray, the one coming down from the top in the Northern Zone, that's Kern River, and then the other one is the Baja Path, so those are PG&E's pipelines, not SoCalGas's.

California uses about 6.4 billion cubic feet per day. This is from the 2014 California Gas Report.

You can see that the total numbers are projected to go down in the future and that's partially efficiency, and partially our Renewable Portfolio Standards, which will decrease the amount of gas necessary for electric generation as we get more renewables online, moving towards our 2020 goals.

So, this table shows the delivery capacities of the major interstate transmission pipelines. And one thing that I will note is that this is 100 percent capacity, and the pipelines aren't typically used at 100 percent capacity. So, this is not the sort of delivery you're getting. But this is, potentially, if everything was perfect, how much you could get.

The point of this table, though, is to show that the takeaway capacity within California is not quite as high. And so you have more gas, potentially, that could come through the border than you have takeaway capacity to get it. So, it's a difference of about 8.5 Bcf and 7 Bcf.

In certain cases, Otay Mesa has a capacity of 400. Right now, there's zero coming over that.

We have a lot of storage in California, which is very helpful for reliable system operation. And this just breaks down Northern California and Southern California. And this is, actually, a fairly good system, I will say, because we do have the ability to supply a lot of the gas in situations where supply is short.

So, we will talk today a little bit about the polar vortex last winter. I know that on the day when there were curtailments, PG&E was able to, from their supply, supply the entire system, the entire PG&E system out of storage, alone, because there was so little supply coming over the pipes. So, that was pretty impressive.

Just talking, quickly, about core versus noncore customers, and firm versus interruptible transportation and storage. For gas supply, these are unbundled, essentially, so these are two separate systems that people need to either contract for or buy.

Core service is typically residential, and small commercial and industrial, defined as less than 250,000 therms per year, and natural gas vehicle customers.

Noncore, large commercial and industrial, and electric generation customers. This is another point that will become important today when we talk about what happened last winter, in February, when there were electric generation curtailments.

So, the difference here is that core customers are guaranteed delivery of gas. Noncore customers, if supply is tight, they aren't paying the extra money for the core services.

Gas transportation, you can have firm, which basically means uninterruptible, or interruptible transportation or storage.

Peak day demand and supply, for reliability the utilities set up these two systems. The PG&E's abnormal peak day and SoCalGas's extreme peak day scenario. Which, essentially, provides a reliability scenario that should cover pretty much all contingencies.

And the way that PG&E has designed it is it's a 1-in-90 year probability event, which equates to an average temperature of 27 degree Fahrenheit, which is around 3.2 Bcf per day. And then total noncore demand of about 2.5 Bcf per day.

SoCalGas has this set up as a 1-in-35 year probability event, which equates to a 40 degree Fahrenheit average temperature for SoCalGas, and 42.6 degree Fahrenheit average temperature for San Diego Gas and Electric.

And then, those two utilities are approved to hold 2.225 billion cubic feet per day of firm storage withdrawal in their combined core portfolio.

Winter balancing rules. So, SoCalGas has this set up, now, to ensure that suppliers are providing enough gas or have an incentive to provide enough gas in the wintertime, when demand goes up.

And the way the winter balancing rules work is that between November 1st and March 31st, the suppliers must deliver 50 percent of usage over a five-day period, or they're charged 150 percent of the highest Southern

California Border price.

Once storage starts to come down, and this doesn't happen very often. I think about 93 percent of the time during that period between November 1st and March 31st, we're in the 50 percent usage over a five-day period sector.

But once storage gets lower, and essentially that's defined as peak day minimum storage plus 20Bcf, then 70 percent of daily usage must be delivered over the pipelines by suppliers. Or, again, there's the 150 percent of highest Southern California Border price charge. And then interruptible storage is cut in half.

Once you get to the peak day minimum storage, plus 5 Bcf, the daily usage supply goes up to 90 percent across the pipelines. And it's the same charge, again, 150 percent, and then there's not interruptible storage withdrawals.

So, and for peak day minimum, I put the definition at the bottom, if people can read it, but you also have your printouts.

PG&E uses a different system. They have high, and low, and operational flow orders, that's OFO, or emergency flow orders, that's EFO.

Essentially, you see this graph that tells you stage one gives a tolerance band of plus or minus 25 percent of usage. And then the noncompliance charge, if you fall outside of that tolerance band, is 25 cents per dekatherm.

So, as these OFOs get called, if they're going up, stage 2, stage 3, stage 4, stage 5, the tolerance band gets smaller and the charge goes up.

Once you get to an emergency flow order, the tolerance band is obviously zero, and the charge is $50 per dekatherm, plus the Daily City Gate Index, so a lot of money.

EFOs are not called very often, but this is basically how they incentivize making sure that suppliers are staying within the proper band when it's either a high or a low OFO.

SoCalGas, right now, has a filing in to use this same design just for low operational flow orders and low emergency flow orders, instead of their winter balancing rules. And that's proceeding A14-06-021, so I've been following that fairly closely.

Gas is scheduled in four cycles. So, the gas day runs from 7:00 a.m. to 7:00 a.m. I should note that's Central Time, so in California that's 5:00 a.m. to 5:00 a.m.

There are four cycles throughout the day, like I said, 9:30 a.m. the day before, again Central Time, 4:00

p.m. the day before, and then 8:00 a.m. day of, which is effective at 3:00 p.m., and 3:00 p.m. day of effective 7:00 p.m.

Why this is important? Gas moves at 30 miles per hour. So, if there are electricity people here, it's very different than how electricity flows. So, if you need to contract for supply at a certain time, you need to plan ahead.

Again, as I said before, PG&E and Sempra will elaborate on their own systems a little bit and probably go into more detail.

I want to thank the utilities, the CPUC and the ISO, for being our speakers and panelists today, and all of you for coming. And please, again, I'll note, comments, written or verbal, are very much appreciated. So, help us out with this report so that we get all of the important information into it.

I am now going to turn it over to -- yes, okay, actually, we're going to move over to our first panel, which is California Gas Utility Perspective.

So, I'd like to invite Roger Graham, from PG&E, and Beth Musich and Gwen Marelli from SoCalGas, up now.

Our first speak on this first panel is going to be Roger Graham, from Pacific Gas & Electric.

Roger is the Senior Manager of Product

Management. His group manages the availability of capacity, pricing, tariffs, and special contracts for PG&E's backbone transmission and gas storage services.

Roger holds a BS in Mechanical Engineering from the University of Colorado, and a Master's in Business Administration from Santa Clara University.

So, I'd like to welcome Roger to the podium.

MR. GRAHAM: Thank you. It's a pleasure to be here and speak on behalf of PG&E, in front of the Commission here, and provide you some perspective on where PG&E sees its infrastructure today, and the in future, with regards to the capacity needed to serve our customers in Northern California.

I wanted to make -- Silas, you did a great job of summarizing California. I think you got your time zones wrong, though, on the gas day. It's 7:00 a.m. Pacific Time. Yeah.

Needless to say, it's an endless amount of confusion in the whole discussion around this, nationally, as everybody thinks in their own time zone. They try to talk in Central Zone, but it never seems to work out just right.

Just a quick summary, and maybe this is all that needs to be said. For PG&E infrastructure, at least today and as we see the near-term future being five to ten years out, PG&E's backbone system is adequate to meet all the demands that we see.

We also believe there's sufficient natural gas storage in Northern California to do the basic functions that it's designed for, which is first to meet peak day demands. The second is to balance intraday demands, and day-to-day changes in supply and demand, as well as allow some optimization of supply purchases.

Like as was mentioned earlier, being able to buy gas in the summer when it's usually cheaper, though not always, and bring it out in the winter to meet these higher demands.

There is, as you'll see, there's plenty of natural gas storage in California. In fact, it has made PG&E's system inverted, that our backbone system actually runs at a higher load factor now in the summer, than it does in the winter, and that is to accommodate all of the gas storage injects. And then, when withdrawals come out, the flows on our backbone system actually decrease, and in some winters substantially.

It was also mentioned that on the long-term view, across PG&E service territory, we see overall demand growth very limited and, in some cases, actually declining.

But there are certain local systems within our local transmission systems that still require capacity additions. So, we are still building new capacity in our local transmission system.

And it’s an interesting phenomenon that as some of the industrial loads, and the energy efficiency of existing residential customers decline, you know, it’s being offset by new residential construction. But that new residential construction is in areas of the State where we don’t have as robust a system.

And so, we’re having to build some fairly expensive local transmission upgrades in order to get to those communities. And one of them is out here in Sacramento.

This is another map, much like the one that was shown earlier, of the Western Interconnects. PG&E is in a really good situation in that we do have straws or pipelines to most of the large basins in the west. You know, whether it’s the Canadian Basin, the Rockies, San Juan, Permian, we can access all of those into our system.

This is a little bit more about PG&Es backbone system that brings gas from the border into the core area of our service territory, which is mostly the San Francisco Bay Area, as well as some of the major communities up and down the Central Valley, Sacramento, Fresno. This is, I think, more just for reference.

Backbone adequacy. We actually make a filing every two years with the Public Utilities Commission. We just made one this last summer and I think that's a good source for the CEC to look at when you want to try to -- you know, because it forecasts out, I forget exactly the number of years, at least ten years, the demand.

In such a way it's not just looking at average demands, but it's not just looking at peak demand, either, because that gives us sort of an unrealistic expectation of sort of what's the sustainable demand on our system.

So, we use a weather forecast or a forecast that looks at both dry hydro conditions, as well as cold winters. And it's a condition that we'd expect to see about once every ten years. So, that's the base forecast that we use when we're trying to decide whether there's adequate capacity in our system.

We do not include short-term sales to off-system. We do send a fair amount of our gas through our system and deliver it to SoCalGas. It, at times, can be upwards of 400 million cubic feet a day. But we don't include that. Most of that type of transportation service is done at significant discounts, so we probably wouldn't expand our system to accommodate those type of sales. So, we do exclude those from the forecast when we look at capacity adequacy.

So, when you look at that, now, on an annual basis we were looking at our backbone system would run at about 76 percent on an annual basis.

I'll show you a slide, next, of what our historicals look like, and it moves around a lot because of gas storage. You do see near 100 percent utilization during some times, the spring and summer months, and very low utilization during other months.

This is what it's looked like for the last three years. You see even our backbone capacity actually varies a fair amount throughout the year. At this point, a lot of this is work that we're having to do on our system, safety-related work that's being done on the system that takes the capacity down. We try to do most of that work in the summer and then the capacity returns back in the winter.

Our system actually can transport more gas in the winter than it can in the summer. A lot of our compressor stations use gas turbines and their horsepower output diminishes with hot, ambient temperatures. And many of our compressor stations are in the hotter part of the service territory. So, we do see in the winter generally a rise in our backbone capacity.

And you can see that this last winter was a very interesting phenomenon on PG&E's system. And that in February, which is our traditionally, you know, highest send-out, the largest demand of our customers, our backbone system operated at about a 50 percent load factor. And again, this is all the gas storage withdrawals that were happening on the system.

So, you can see some winters it's quite dramatic that the use of our backbone system decreases substantially in the winter and then increases, again, in the summer.

Here's a list of the gas storage assets that are in Northern California. PG&E, today, owns or controls about half the natural gas storage inventory capacity in Northern California. And the independent storage providers own about the other half.

They're fairly good geographically disbursed throughout the PG&E service territory, though there is some concentration of these on the Northern System, the Wild Goose Central Valley storage in Lodi are on pipelines that we consider our Redwood Path, in the northern part of the State.

And at times there has been some congestion between gas that wants to come in at Malin, and come down Line 400-401 and storage withdrawals coming out of Wild Goose in Central Valley, and Lodi.

There is a process in our tariffs to deal with that type of congestion. It's happened a couple of times last summer -- or the summer-before-last, actually. We don't think that's a problem that's going to be common, but it can happen because of the very large withdrawal capacities that those independent storage providers have.

Looking at kind of the peak day supply and demand balance, you kind of look at supplies. We don't assume that 100 percent of our backbone system will be full of gas on a peak winter day. A good assumption is maybe 67 percent of it, as well as you probably aren't going to be able to access 100 percent of the storage withdrawals in the system on any given day.

Some gas storage facilities, actually, as the gas is drawn down in the reservoir, they're delivery rates decrease, so that if a cold winter day or a peak day occurred later in the winter, some facilities won't have as much withdrawal capacity as what's listed on their nameplate.

Other facilities don't have that same problem. But on average, we take an 80 percent look. And then we look at the type of demands on our system, an average winter day is about 3,400.

Our historical peak day, which occurred, the highest send-out we've had on our system occurred last December 2013, at just about 5 Bcf. That was a day that informed us quite a bit on how big demands really can be.

We've always focused a lot on forecasting what our core demand will be on a day like that, about 3.2, a little over 3.2 Bcf a day.

But what we don't have a really good handle on is how much noncore load that we'll have. I mean, it's fairly easy to forecast the commercial and industrial loads, but the electric generation load that will occur on that day is something that we really don't have a good forecast on.

And last December 9th, was a -- it was actually quite surprising to us how much electric generation wanted to access the system on that peak day.

And so, I think people may have seen this slide from me six months ago, or a year ago, and the noncore load was 1,800.

We now think that on a peak day that the noncore load will be more like 2,300, 2,400.

Again, talking a little bit about our local transmission system. We do see demand growth in the Sacramento area and a fair amount of growth, now, in the Santa Clara County, or Silicon Valley.

Here in Sacramento, really North Sacramento, you know, a lot of new housing and commercial growth. And the same is happening in Santa Clara County. It’s probably more tilted a little bit towards commercial growth, as opposed to residential. That area’s reasonably well-built out, so they are starting to build quite a few homes up into the hills around Cupertino, Saratoga. A lot of infill projects. So, we are seeing a fair amount of housing growth.

I think over the next 15 years, we’re estimating upwards of 100,000 new residential connections, just in the Sacramento area.

So, we do have a proposal out to build a very large pipeline from our backbone system, which is actually out near I-5 -- I’m sorry, out near highway -- yeah, I guess I-5 out there that far north, over to Auburn, in the North Sacramento area, so that we can see that.

And the other places where we are seeing, potentially, the need for some additional local transmission capacity is in the Fresno area and North Bay, the Marin County area. Those systems are really --

they're constrained at the moment. We do a lot of manual operations and we use compressed natural gas, and liquefied natural gas augmentation. So, we bring natural gas in, in trailers, either in a compressed form or in a liquid form. The liquid form, we have to gasify it, and we put it in the local system to increase the capacity at the local system. So, we're doing that fairly extensively across our system.

But at some point the demand growth is such that we'll have to probably put in some more capacity in those areas.

That's all I have.

MR. BAUER: Thank you, Roger.

Next up we're going to hear from Sempra SoCalGas. We have Beth Musich, who is the Director of Gas Operations Staff.

Beth is currently -- well, in her capacity she manages the training compliance, gas standards, new business processes and distribution integrity management programs for both SoCalGas and San Diego Gas & Electric.

Beth holds a Bachelor's Degree in Mechanical Engineering from Colorado School of Minds.

With her, and talking right after her will be Gwen Marelli, who has worked for -- she's the Energy Markets and Capacity Products Director. And she has worked for Sempra Energy for over 20 years, and currently serves in the role I just noted.

In this capacity, she manages service to the largest natural gas customers of Southern California Gas Company, specifically large electric generators, enhanced oil recovery customers, and wholesale customers.

She holds a Bachelor's Degree in Mechanical Engineering from UC San Diego and a Master's in Business Administration from Pepperdine University.

So, I'm going to welcome Beth to the podium.

MS. MUSICH: We're going to tag-team.

MR. BAUER: You're going to tag-team.

MS. MUSICH: Good morning. So, just a quick overview. Southern California Gas Company has been delivering clean and safe, reliable natural gas to its customers for more than 140 years. It's the nation's largest natural gas distribution utility, providing energy to 21.3 million consumers through 5.8 million meters, for over 500 communities.

Our service territory encompasses approximately 20,000 square miles, and it's a diverse terrain throughout Central and Southern California, from Visalia to the Mexican border.

So, SoCal owns and operates an integrated transmission system consisting of pipeline and storage facilities. Through its network of transmission pipeline and four interconnected storage fields, SoCal delivers natural gas to over 5 million residential and business customers.

The transmission system, as you can see, extends from the Colorado River on the eastern end, to the Pacific Coast on the western end, from Tulare in the northern portion and down to the Mexican border in the south.

Our transmission system was initially designed to receive and redeliver gas from the east to the load centers in the Los Angeles Basin, the Imperial Valley, San Joaquin Valley, and our North Coastal areas, and then down to San Diego.

As our customers sought to access new supply sources in Canada and the Rockies, we modified our system so that it can concurrently accept deliveries from the north.

As a result, the system today delivers over 3,875 million cubic feet per day.

Primary supply sources are the Southwestern United States, the Rocky Mountain Region, Canada, and California's on and offshore production.

So, the San Diego Gas Transmission System. It consists primarily of two high-pressure, large-diameter pipelines that extend from Rainbow Station, located to the north, in the Riverside County, and they extend south to Rainbow -- excuse me, and extend south from there, down into San Diego.

Both pipelines terminate at SDG&E's City Gate Regulator Stations in San Diego.

The pipelines are interconnected approximately at their midpoint and, again, at their southern terminus.

The northern crosstie runs between Carlsbad and Escondido in the middle, while the southern crosstie runs through Miramar.

San Diego has a Moreno Compressor Station, located in Moreno Valley in the north, and it boosts the pressure into SoCal gas transmission lines serving the Rainbow Station. A much smaller compression station is located at the Rainbow Station.

We have an underground gas storage configuration. We have four fields. We have Aliso Canyon, in Northridge, Honor Rancho in Valencia, La Goleta in Goleta, which is near Santa Barbara, and Playa del Rey, which is in Marina del Rey, right near the airport.

Together, we have a combined inventory capacity of 137 billion cubic feet. A little bit different than the slide that Silas presented. And a combined firm injection capacity of 850 million cubic feet per day, and withdrawal capacity of 3,760 million cubic feet per day.

There’s many components, many factors are taken into account for our ten-year planning horizon. Firstly, we rely on the California Gas Report. And in the 2014 Gas Report there was a comprehensive outlook for natural gas requirements and supplies for California through the year 2035.

Although we rely on that, it’s important to note that the projects in the California Gas Report are for long-term planning purposes and they do not, necessarily reflect day-to-day operations of our pipeline.

So, the closure of San Onofre, or San Onofre Nuclear Generating Station, took out 2,200 megawatts of electric generation in 2013. That was approximately 9 percent of the electricity generated in California.

We’re forecasting approximately, almost 2,000 megawatts of new, gas-fired combined cycle, and peaking generating resources in our service territory by 2025.

This forecast also assumes almost 7,000 megawatts of older plants that are retired as a result of the State’s once-through cooling requirements.

The Los Angeles area plants have until 2020 to comply with this ruling.

Another factor that comes into play for our planning is the fact that California's currently on track to reach the 33 Percent Renewable Portfolio Standard by 2020. It's expected that solar and wind will make up most of the new renewable generation. And electric system operators must balance the electric demand with supply resources on a real-time basis.

Historically, system operators have relied on dispatchable gas-fired generation that can respond quickly to these changes in demand to keep the system in balance.

The substantial increase in renewable resources will present an additional challenge for all of us. We must deal with real-time, unanticipated variations in intermittent renewable power.

In addition, these resources greatly increase morning and evening ramps as both wind and solar resources can come online and offline very quickly.

The intermittent nature of renewable generation is likely to cause the electric system to rely more heavily on quick start generation, and that's quick start that can come on within three minutes and to full power in ten minutes.

I don't know if we want to talk a little bit more about some of the peak days.

MS. MARELLI: So, as far as our planning standards, we have a 1-in-10 planning standard for our noncore customers, a 1-in-35 for our core customers.

Our system can do 6 Bcf of capacity per day, and that's a combination of the withdrawal and receipt points capacity. And like Roger mentioned, you get some interference between the withdrawal and the receipt point capacity. So, if you look at them individually, they don't add up to 6 Bcf.

The highest day we had was 5.3 Bcf in the winter of 2000, and then we got close to that these last couple of years.

And our capacity-constrained areas, we have two potentially capacity-constrained areas. Those are the SDG&E system and the Rainbow Corridor as a combined area, and then the other area is the San Joaquin Valley at the northern end of our system. So, those are capacity-constrained areas.

MS. MUSICH: So, we currently have a new project at Aliso Canyon. It's to add new injection capabilities. Aliso Canyon's in Northridge. It's about 25 miles north of Los Angeles.

And we're in the process of replacing existing, obsolete compressors with state-of-the-art technology to help meet the region's demand for natural gas.

Currently, there's three natural gas turbine-driven compressors and they're used to inject gas into the storage fields.

This project is scheduled to be completed by the end of the fourth quarter of 2016.

So, we're ready to go onto the next.

MR. BAUER: Thank you to our presenters.

We're going to move on to our first panel, which is about Southern System reliability issues.

The moderator for this panel is going to be Ivin Rhyne, who's the Office Manager for the Supply Analysis Office.

At this time, I want to invite all of the members of the first panel to come join everybody at the table. And I'm going to turn it over to Ivin.

MR. RHYNE: Thank you. So, as the members of the first panel get up here, I'll do short introductions for everyone.

But just to sort of set the stage, one of the interesting things is that as we move forward there is the discussion of how much gas is available is at some point, and sometimes here in recent history been overshadowed by whether or not we could get that gas to the right customers, at the right time.

And that has led to a proposal that's before the California Public Utilities Commission to add a new pipeline to the Southern California Gas System.

I will sort of be clear, we are not here to attempt to trample on any of that decision making process that the PUC is going through. That is an important and sort of constitutionally-mandated activity.

What we're doing here today is having a discussion around the table about what that proposal and some alternative proposals are, what it means for California in sort of a larger context.

And I think it will end up influencing some of the discussion that we have later today as we talk, perhaps, about the interaction between the gas and electric system, as well as some of the other questions about supply and the supply availability for California.

So, I want to sort of be clear about that before we kick off this panel.

The other thing is, is I have a number of questions here. They've been published to the docket. We will certainly try to get through these. But as these panels develop, certainly, we may find that there are questions or avenues worth further discussion, more deep discussion. I'm not going to try to limit us only to sticking to these exact questions, if we find that there's an area worth further discussion.

So with that, I will mention that we have Beth Musich and Gwen Marelli here on this panel. They've already been introduced.

And also, Chair Weisenmiller will be joining us here at the table, although I don't have any particular questions for the Chairman. But, certainly, he can feel free to inject, as well.

Just a very short introduction. We also have Gregg Russell, the Vice President of Marketing and Interstate Pipelines, and Energy Transfer for TransWestern's Tiger and Fayetteville Express Pipelines, managing all commercial activity.

Gregg has 25 years' experience managing commercial activity relating to interstate natural gas pipelines, storage, and LNG facilities.

This includes trading and marketing, transportation and exchange, nominations and scheduling, business development, mergers and acquisitions, strategic planning and analysis, pipeline operations, contract administration, and customer service.

Sounds like a pretty well-rounded resume there.

Gregg graduated from the University of Houston with a BA in Economics, and resides in Houston.

We also have Jim Schoene --

MR. SCHOENE: Schoene.

MR. RHYNE: Schoene, thank you. General Manager of the North Baja Pipeline and Account Director of Gas Transmission Northwest.

Jim is currently employed by TransCanada as the General Manager for Commercial Activities, the North Baja Pipeline, as I mentioned.

The North Baja Pipeline, just to be clear, is a wholly owned subsidiary of TransCanada Pipelines, Limited.

Jim graduated from the University of Michigan with a BS in Engineering, and has held various engineering, construction, and marketing-related positions since graduation.

And, finally, we also have Gregg Russell is currently the -- not just finally, we have one more. But Gregg Russell is currently Vice President of Marketing for Energy Transverse TransWestern.

Oh, yes, I did. Sorry, wrong side of the paper here.

We have Norm Pedersen, an attorney with Hanna and Morton LLP. Norm has extensive experience in energy law and related areas. He has represented electric generators, electric utilities, oil and natural gas pipelines, industrial end-users, government agencies, and natural resource development companies in a wide range of energy-related matters before State and Federal regulatory agencies, courts, and legislative bodies.

Mr. Pedersen's a member of the Energy Bar Association, and various state and local bar associations. He has a BA degree and an MA degree from the University of California, at Berkeley. His law degree is from the University of California, at UCLA Law School. He is admitted to practice in California, District of Columbia, and before various Federal courts.

We also have Anthony Sanabria -- got that one right -- Account Director of Business Development for El Paso Natural Gas Company.

In 2013, Anthony joined Kinder Morgan as Account Director of Business Development. And as Account Director, he is responsible for connection of new supplies and markets, development and maintenance of customer relationships, coordination, and sale, and acquisition facilities.

Anthony is a 1992 graduate of Penn State, with a Bachelor of Science Degree in Petroleum and Natural Gas Engineering.

So, I want to thank all of our panelists for being here today and we will go ahead and get started.

The first question really is focused on -- okay, so our first question is really going to be focused on the Southern System minimum, and I know that you have a presentation that will help sort of clarify the issue for us. So, I'll invite you to the podium to do that. Thank you.

MS. MARELLI: Okay, so, yeah, this is a similar -- I think it's the same slide that Silas used earlier. And I've circled on this one the Southern System.

And the Southern System is unique in our service territory in that the supplies in our storage fields can't reach the southern part of our system. So, we rely on flowing supplies to reach this area.

A limited amount of gas can come down from the northern receipt points, you know, and then back its way over, and then there's also the pipe -- it's not marked. But there is a small line that can give up to 80 million feet per day from the northern receipt points.

The majority of the gas for the Southern System has to come from the El Paso System that's at Blythe, at the right side of the slide, where it says El Paso, Ehrenberg.

So, this is a unique problem for our system in that all -- the rest of our system is very interconnected. The Southern System is just not nearly interconnected as the rest of our system.

We have very liberal rules with where you have to bring your gas. You can be anywhere on our system. You can be sitting on the very southern tip of the SDG&E system and bring gas in through PG&E, or through any of the northern receipt points.

And so what this does is that when prices are such that it doesn’t make sense, economic sense to bring gas into our Southern System, sometimes we have issues getting gas into that Southern System, and that happens to be the place where we need to have that flowing supply.

So, what this means is that every single day, 365 days of the year, we do have a minimum amount of supply that has to be brought into that Southern System, and that’s posted on our Envoy website every single day.

On days when not enough gas is brought into the system, then we, as the system operator, need to go out and purchase supplies, and bring them into that Southern System to make sure that we can serve the needs of those southern customers.

We’ll go to this one. Actually, we’ll go to that one. So, what this slide shows is if you look at that, I'm going to call it blue, and the green bars, that's the amount, the quantity of gas that the system operator has brought into the system from 2009 to 2014. And you can see that amount is going up.

The green is another tool that the CPUC allowed us to have, which is a baseload contract, so that green is gas that comes into our system, you know, every day in the wintertime.

And then the blue are spot purchases that we have to go out and purchase on a daily basis.

The blue line and the purple line, those are the number of requests that we received and the number -- and that's the blue line is the number of requests that we received. And the number of flow days is the purple line.

So, as you can see, the quantities that we're having to purchase are going up, the number of days that we're having to purchase is going up, and the number of requests that we're getting is going up.

So, this is what brought us to the point of filing the application that we were talking about.

Just to show you some of the numbers, this shows the quantity, the decatherms on that first line, the purchases. So, you know, we were doing about 7 Bcf in 2009 and in this last year we did, you know, 42 Bcf, so quite a bit more gas that we're having to supplement into the Southern System because customers aren't bringing gas into the Southern System.

And then, the costs have also been increasing. They started at about $2.2 million and in this last time frame that we're showing here was $15.5 million, and that's just for the gas purchases.

Then, we also offer discounts into our Southern System. Off of the backbone rate that customers pay, we'll offer a discount to try to incent gas to come into that Southern System.

So, the total cost, anywhere from $2.2 million to, recently we paid $23.4 million. And then that goes right back to customers. Customers pay back those costs for the gas that we buy for them.

So, we do have tools that we've gotten over this time frame, since 2009, to try to improve the reliability of the Southern System. One of them was a purchase of Line 6916 from Questar, and that's up to 80 million a day of gas that we can get from our northern receipt points down to our Southern System.

We have what we call the MILC, the Memorandum in Lieu of Contract. And that's a contract between the system operator and SoCalGas's Gas Acquisition Group. And so what we've done, as a system operator, is contracted with Gas Acquisition to agree to bring in supplies that the core needs for the Southern System, and bring those directly into the Southern System.

And in exchange for that, they don't have to pay the SRMA costs, if there are any for that particular day.

Recently, as I mentioned, we had approved the -- that was last year, we had the approved, the ability to bring in up to 255,000 decatherms per day at Ehrenberg, on a baseload basis in the wintertime. And that was very helpful this past winter in getting us, you know, through the winter.

We also have the ability to do the spot gas purchases and we have a mechanism set up, a safe harbor of sorts, so that if we purchase the gas within these parameters that are set up for us, then those purchases are deemed to be reasonable.

And we also will discount, as I mentioned, the rate. We had been able to discount only the interruptible rate, and we recently got approval to also discount the firm rate into the Southern System.

I'm going to go to the pipe so I can show you what it looks like. So, if you look on this, the red line is the project that we're proposing. It's a 63-mile pipeline, a 36-inch pipeline going from Adelanto down to Moreno. So, that's tying our Northern System to our Southern System. And it's 30,000 horsepower of compression. So, that's what we're proposing in this application.

So, some of the benefits of this is that pipeline will be able to move up 800 million cubic feet per day of supply from all of those northern receipt points, from all the ones that are on the northern side, as well as our storage gas. And that's a unique feature of the north/south pipeline is that you will be able to move not only the receipt point gas, but the storage gas.

That became an issue in some of the previous times because we weren't able to get storage gas and no gas was coming into our system.

It will also, as just a coincidental benefit, will increase our receipt point capacity by 300 million cubic feet a day of the northern receipt points.

And because it does this interconnection of the north and south, and allows that storage gas to flow to the Southern System, it provides quite a bit of reliability for the Southern System that they don't have today. And we believe that will also increase the potential reliability of the electric grid because that does tend to be one of the places, with the San Onofre outage, that we have a lot of new electric generation.

SoCalGas and SDG&E don't believe that non-physical solutions will fix this problem. As I mentioned, no access to storage. And then, even if you contract for upstream supplies beyond the Blythe receipt point, you're still tied to the Ehrenberg -- or to the El Paso System.

And we'd like to have a lot more supply diversity so if something's happening on the El Paso system or if, you know, the prices are more there, we'll have the ability to bring the gas down from those cheaper receipt points. And we think that will provide our customers with the most flexibility and the most reliability.

And my last slide just shows the average residential bills, what this is going to do to a residential bill. And then, also, for our noncore customers, a transmission level rate. It looks a little wonky because all of the increases on the backbone or the transmission level rates go into the backbone rate.

And then, as you can see for a residential customer, it's about a one percent increase in their monthly bill.

And that's it.

MR. BAUER: All right, so next we have Greg

Reisinger, from the CPUC, who's going to give us a short presentation about the Southern System minimum flow issue, requirement and management tools. I'd like to welcome Greg.

MR. REISINGER: So, the good news is that most of my numbers are going to look very familiar to the numbers Beth presented, because it's nice when we're presenting on the same topic that the numbers work.

The bad news is you're going to have to hear some of the same comments.

Just to begin with is there is a Decision 07-12-019 that states that each October SoCalGas needs to file an annual compliance report that basically presents all the transactions regarding purchases to meet the minimum flow requirements on the Southern System.

And that's a detailed -- we go through and do a detailed look at all of those transactions to make sure they comply with certain criteria that are set up and that are documented in SoCalGas's Rule 41.

Most of those criteria are very clear cut. You know, there's a range within which certain purchases have to be made to be deemed reasonable. There's other circumstances and criteria that define how the baseload contracts that Beth had mentioned need to work.

And by and large, in fact I think in the last report that just came out for the period 2013 to 2014, of the 150,015 transactions, 65 percent of them were within the safe harbor limits, about plus or minus 10 percent. Purchase and sales of gas were within 10 percent of the ISE index.

The remaining -- and that represented, though, only about 12 percent of the sales dollars, or the purchase and sales dollars.

If you look at the base loads that Beth had mentioned, those contracts all fell within the criteria that were set up. They delivered about 78 percent of the purchase dollars of the purchases.

So, let me see if I can do this right. Oh, okay, sorry, that helps.

So, as Beth mentioned, when the decision was first put in place, there were basically two tools, the spot purchases, which have been the most heavily used tool, and then the second was a request for offer, for offers that SoCalGas could use.

And then the third issue here was an expedited device letter, approval process for contracts. We probably haven't, from our side, been able to get through that process on an expedited basis.

Over the time frame of these -- of the different ACRs -- okay, over the time frame, and this follows the same pattern that Beth had mentioned, is we've seen a significant growth in the level of purchases needed to maintain the Southern System.

And those have gone from, at the low point there it was about $8.3 million, for about a 1 Bcf, up to about $185 million in purchases this past year, for around 15 -- or I'm sorry, 37 million decatherms.

And as that's gone on, the net costs have increased significantly. Although, as you'll see, not at the same rate.

Since most of the purchases that are made are then -- that gas is then resold at the city gate, there's a significant difference between the net cost of these purchases and what the actual purchase was.

And just looking at it, the net cost the last several years, the last two or three years has been about 10 percent or so of the total purchase price of the gross.

So, as this has grown, one of the things that's happened is it's become clear that there were some refinements that could be made, and SoCalGas had the opportunity, under the original decision, to request additional management tools for the Southern System purchases to maintain the minimum flows.

And over the last, probably, three years, several have been included. The one is the Memorandum in Lieu of Contract was first put in place about two years ago. And then, just recently, it was set up on a basis where it could be renewed each year on a preapproved basis, as long as it met certain defined criteria.

A similar thing with baseload contracts. A few years ago there was a proposal for some baseload contracts. They were not approved on a timely basis, but it did allow us to define some criteria for what the CPUC would look for as a reasonable baseload contract.

And now, as long as those -- as new contracts meet those criteria, they're approved also on a preapproved basis.

And then there's also the ability for SoCalGas to purchase gas at Blythe and transport it through an affiliate into Otay Mesa, when gas is needed specifically at Otay Mesa, and when that process is less expensive than buying, than making spot purchases at Otay Mesa.

And finally, as mentioned earlier, there's now discounts allowed for both interruptible and firm, with a particular twist that firm deliveries -- firm Btus was, in the past, always had alternative delivery point rights.

So, SoCalGas may offer a discount to help supply the Southern System, but for firm customers they could actually deliver that and receive the discount into the Northern System, so it wouldn't have helped.

So, the request came in that can we alter that to take away those alternate points and to designate that it has to go into the Southern System? And that was also just recently approved.

So, if you look at it over the time frame, the cost increases have been much -- have grown much less -- the net cost has grown much less quickly than the total purchases. And we'd like to believe that through the Commission-approved tools, and what have been proposed, that SoCalGas has been able to basically maintain the costs at a relative -- on a per-unit basis, at a relatively stable level.

If you look at it, the last three period we examined fall within between 33 and 40 cents per dekatherm.

So, absent that one year, one period, '10-'11, it's been a relatively stable process in terms of the net cost per unit.

So, that's all I have for you.

MR. RHYNE: All right, so thank you, Greg. And thank you, as well, to Beth and Gwen.

So, we're going to get into our questions now and I will ask the panel members, as you -- when you speak for the first time, just briefly state who you are and who you're with to make sure that we get this for the court reporter, as well.

So, the first question, as I mentioned, really sort of focuses on Southern California gas. The graphs shown by both you and by the PUC show a dramatic increase in flow days and the cost associated with this.

And, really, what are the circumstances of demand versus supply that are driving this increase in flow days?

And as a follow-on to that, to what extent has this minimum flow issue affected reliability in the Southern System?

MS. MUSICH: So, Beth Musich, SoCalGas. Yes, so the -- we do have a minimum flow every day of the year.

What I think has happened in the last few years is, certainly, the San Onofre outage has caused more gas supplies on that. There have been additional electric generation that's been sited on our Southern System.

And then last year, the unusual price patterns across the nation caused gas to go away from our entire system.

So, I think all of those things have exacerbated our Southern System issues and under what circumstances and -- so, the two things that are going to exacerbate problems there are going to be if there's a supply issue upstream or extreme pricing differentials between California and other states.

Or if, as has happened several times, if it gets very cold and we have a lot of core usage then, you know, you may just not see enough gas being delivered to meet those needs. And that's why we've ended up a few times in curtailment or near-curtailment situations.

MR. RHYNE: Okay. Any other panelists wish to weigh in on that particular question or any other follow ups?

Norm.

MR. PEDERSEN: Yes. Thanks, Ivin.

First, I'd just like to start with a couple of comments about the presentation Beth just made before this one, where she was talking about the Southern System and about the north/south project.

First, Beth mentioned the line 6916 that can deliver 80 million cubic feet per day from the Northern System to the Southern System, and that went into operation something like a couple of years ago.

But for a long time we have had two other interconnections between the Northern System and the

Southern System that should be mentioned.

There shouldn't be the impression that -- folks shouldn't have the impression that the Northern System and the Southern System are completely unconnected from the north, other than through that line 6916.

About 200 million cubic feet a day, on average, according to Dave Bisi, at SoCalGas, can move through the Chino and Prado interconnects between the north and the south.

So, there is some deliverability. But, nevertheless, the bulk of the supplies do need to come in through Ehrenberg.

And while I'm on it, I just couldn't help but notice your last slide, Beth, that you particularly pointed out, where you said the rate impact of the north/south project would be 1.1 percent, I think for residential customers.

But the backbone rate would go up 81 percent, your slide on page 17 shows. And for every them that is delivered to the core, that therm has to come through the backbone system.

And in a previous proceeding we had at the CPUC, parties agreed that around 93 percent of whatever a producer pays to move gas through the backbone to get to the market, the city gate, so that gas can go on to residential customers is ultimately picked up by the downstream customer. So, the core would have a big impact from the north/south project.

But I'd just like to turn to what Beth was just talking about. In SoCalGas's testimony, they pointed out actually four very different threats that they saw coming up for the Southern System.

They've talked at some length about how flowing supplies might not be available for delivery to Ehrenberg for the longer term primarily because gas is started to flow off the Southern System to El Paso.

Secondly, they pointed out that gas might not be delivered to the Southern System, at Ehrenberg, from El Paso, due to adverse weather conditions. And as just about everybody in this room knows, we had a couple of those this last winter. Winter 2013-14 we had the early December weather event and then in early February what folks called the polar vortex event that affected the entire nation.

Thirdly, in their testimony they pointed out that the force majeure events may occur on the El Paso System that would impair deliveries into Ehrenberg.

And then, lastly, they did talk about limitations on the Southern System, itself.

And when we get into some of your other

questions, Ivin, we can talk about the solutions to those different threats. But certainly, from our point of view, yes, there are those threats, but those threats are manageable.

MR. RHYNE: Okay, thanks Norm.

Any other comments before we move into our next question? No.

All right, so in looking at the events that may have sort of precipitated the need to sort of file this, on December 20th, 2013, Southern California Gas, San Diego, they filed their application authority to recover North/South Project revenue in customer rates, and for approval of related cost-allocation rate design proposals.

Subsequently, two other pipeline companies have filed initial details on alternative pipelines, and another filed comments alluding to a pipeline proposal that would be filed in the future.

I'll ask -- I'll actually ask the other pipeline companies maybe to go first. Could you each, those here at the table, speak to -- describe the proposed pipelines and explain what the potential benefits are from those projects and any potential drawbacks?

MR. SANABRIA: Anthony Sanabria with El Paso Natural Gas.

We have made a proposal to build a pipeline in Arizona to basically parallel one of our existing pipelines to move gas from our northern mainline down to our southern mainline, for increased deliveries to Ehrenberg.

In addition, this would also allow us to take gas back from SoCalGas, from their Northern System, to our system and route it around to them.

So, just like their north-to-south project, it would interconnect their northern system with the southern system.

We see our project having four distinct advantages. The first is scalability. They're proposing a project to build 800 million a day. Ours can be scaled anywhere from 300 to 800 million a day, as other people on the proceedings have questioned how much is truly needed.

The second is ours is actually a brown field project. We have an existing right of way. We have the compression we're going to put in is all at existing compression stations, so it has a lot smaller impact on the environment compared to a green field project, like they're proposing.

The third is timing. We can get our project in within three years from whenever SoCalGas would enter into a contract. So, we're looking -- if they were to decide at the end of this year to do something, we could be in serve 2018. They're looking at a 2020 date.

As they've noted, there is a need to get this in service right away.

One of the other things with timing is their project has anywhere from a 50 to longer life that they'll be required to charge customers. Ours is a fixed 20-year term.

Which brings out the fourth and probably most important aspect of our project is cost. Our cost is significantly less, anywhere from 50 percent to 30 percent lower, depending on which scale they were to pick.

More importantly, ours is a fixed cost. The annual revenue that we've project to them is a set amount. It's what they would pay no matter what the cost of the project and service is.

Kinder Morgan has decided we bear all risk of putting it in service, once they were to agree to a contract.

Their project has an unknown cost. Initially, it was $628 million. It's been revised at $621 million, but that included a major decrease in the scope of their project.

So, I think that's the benefits of our project. It gives the same type of reliable service, but at a much lower cost for their ratepayers and for a much lower duration of time.

MR. RHYNE: So, Anthony, I'm going to ask you to speak to the other side of the coin, though. Are there any drawbacks that we can put on the table now, that you know of with that particular proposal?

MR. SANABRIA: We don't see, really, any drawbacks. We accessed their system at Topock, where they have their deliveries to them, so we can move gas from their system to ours.

We've included an option to move gas from their storage interconnects, off our Mojave System back. It gives about the exact same reliability that we see they have.

And one of the things they've pointed out is some issues of, well, the reliability of gas deliveries at Ehrenberg. In our testimony, we've provided data that shows that we've never really had any -- I think it was a 99.99 percent reliability over the last three years for deliveries. And for a cost that's significantly lower, it seems like a much better benefit to the California ratepayers.

MR. RHYNE: Thank you.

Jim? Gregg?

MR. SCHOENE: Thank you. I'm Jim Schoene, with North Baja Pipeline.

Do you have --

MR. RHYNE: We're going to pull that up for you right now. I'm not sure how clear that is. Okay, there we go.

MR. SCHOENE: Well, I've seen it before. This proposed pipeline would interconnect with SoCal at both the North Needles and the South Needles SoCal compressor stations, continue south and interconnect with SoCal at their existing pressure station at Blythe.

The top 15 miles, depicted in blue, is 24-inch pipe. The bottom 90 miles is 36-inch pipe.

We could site compression at the SoCal South Needles Compressor Station, if it was required. That remains to be answered.

The pipe, not coincidentally, has a nominal design of 800 million a day. It can be kind of whatever we need it to be or want it to be, taking SoCal's lead for volume.

1,150 MAOP pipe. It traverses incredibly arid geography, nearly no population impacts. It is very much a green field pipeline.

We've looked at this route before,

coincidentally, for other purposes, so it's not completely unfamiliar to us.

Far fewer environmental entanglements, I would say, given at least with respect to people. I was about to guess how many people might be proximate to the pipeline, and I think we could get them all in this room.

An endangered species or two, I imagine, along the way, probably not dissimilar to the route we have from our existing North Baja Pipeline, from Ehrenberg to the U.S./Mexico border. We successfully mitigated those impacts when we built the pipeline. We received a certificated from the FARC, in 2008, to expand the pipeline, although it was never built, with all the environmental issues addressed there and fully mitigated.

Similar to El Paso, the contract we would contemplate with SoCal would be based -- would have a rate based solely on what they contract for. We would bear the risk of under-subscription or over-subscription. Over-subscription being a problem we'd love to have.

But SoCal would not be exposed to the full cost of the pipeline, only the capacity which it contracted for.

I should go back to the interconnect with Blythe for a moment. We do have an existing interconnect there. We have moved gas through that interconnect into SoCal from time to time. And we have taken gas from El Paso, at Ehrenberg, and moved it south into Mexico, and then I'll call it around the horn, up into Otay Mesa, from time to time, when SoCal needed volumes at Otay.

It does satisfy the minimum flow requirement criteria that SoCal stipulate in its application. In other words, it transfers gas from the north to the south through the existing interconnect.

The cost was or is estimated to be about $585 million, minus $82 million of compressionism needed. Slightly lower than SoCal's present estimate.

I think that's the substance of the project physically. And with that, I'll give it to Gregg.

MR. RHYNE: Thank you. Gregg.

MR. SCHOENE: Unless there are any questions.

MR. RUSSELL: Thanks, Jim. Gregg Russell, with TW.

You know, our proposal is not really that dissimilar to either what El Paso is laying out or what North Baja is laying out. Again, what we're trying to do, and I guess let me start by saying that we do agree that Southern California does need some additional infrastructure.

We'd like to put it in, in a more cost-effective method. Our project is also scalable. We can do anywhere from 500 to 800 million a day. And that can either be that we can start the project at 800 million a day, if the capacity is needed, or we could start smaller. We could start it at 500 million a day and then ramp up, again, as necessary, and that's just with the addition of compression.

As with what Anthony said, timing is a big thing. I think we have laid out in our initial round of testimony that more or less from today, if we were to move forward, we could have this project in place by 2017, versus what SoCal's looking at as the 2019 time frame.

And that timing is really very, very important from the stand point of what's going on as far as exports into Mexico. A lot of the congestion, quote/unquote, that everyone talks about on El Paso's South Mail Line certainly would be probably ramping up in that 2018 time frame.

So, you're in a situation where you've got increasing Mexico exports but, yet, SoCal does not have a solution to its Southern System that is certainly within a timely sort of a basis.

One thing, though, I would like to sort of talk about, and this is probably a support for not just TW's proposal, but also for El Paso and for North Baja, is that SoCal repeatedly mentions that storage is integral to their proposal.

I think we're kind of mixing reliability of supply versus reliability of pipeline capacity. You know, storage supply is not the sole reliable supply for the Southern System.

I'm afraid that what's going to happen is Southern California is going to get into a situation where they're paying close to $200 million more for a project that is based on supply that might not be there.

I think we all know what happened this past winter with SoCal's supply situation, as far as their storage inventories go, which they were at a low level for many days during this past winter.

So, if you're putting all this infrastructure in solely under the premise to move storage gas down to the south, and the storage gas isn't there, I'm not sure, really, what this project is accomplishing as a whole.

And then, I guess, finally, when you talk about supply diversity, I guess I'd ask the State of California to look at supplier diversity. With all due respect to El Paso, they are a large supplier into

Southern California.

And I guess what TW would like to do is enhance our footprint to enable to serve the citizens of Southern California. So, consider supplier diversity.

MR. RHYNE: Thank you. So, the issue you bring up actually gets maybe to my first sort of deviation, but maybe a further exploration.

The discussion here has been about increasing the supply, the amount of gas supply to the Southern System.

But I think, Gregg, that you brought up an interesting question is we have to maybe be more explicit about where that supply could come from.

The Southern California Gas's proposal focuses on the more western part of the system and would be a more direct connection to accessing gas that's in storage.

Whereas, these other, the other two proposals that we have push that pipeline eastern, push it more towards the Needles/Ehrenberg/Otay Mesa -- not Otay Mesa, but the eastern border with California. And that really tends to be about bringing those supplies in at the border.

Is there a tradeoff, in the panelists' minds, between making that access to storage more accessible or is there a benefit to going one way or another. And I'll let SoCalGas sort of kick that one off.

MS. MUSICH: Thank you. The beauty of our north/south project is it's not just about storage. And so, I'm sorry if you thought that was what it's about. The nice thing is it does give you access to the storage, but it also gives you access to the Northern El Paso System, to the TW System, to the Kern River.

So it provides, of all of the projects, the access to the most supply. So, yeah, that's what I love, and that's why we chose where the pipe is going to go because it does give us the most supply diversity, not just from storage, but the interstates.

So, if there's a problem on any one pipe, we have access to all those other ones, as well.

MR. RUSSELL: I guess, but to put a very fine point on it, again, TW's proposal would carry gas from TW's mainline. It would go south, it would also touch El Paso, it would touch Southern Star. And then, it would also link up with El Paso's South Main Line.

So, what we would literally be doing is being or providing a supply header for SoCal's gas system. So, in other words, instead of one single delivery point off of TW, there would be actually four delivery points that SoCal could use in concert, however they'd like to, to complement their system.

So, the question is, is $200 million worth that one additional supply component, which is storage, and you're not guaranteed that those molecules of gas are going to be in the storage system when you need it.

MR. SANABRIA: To reiterate what Gregg said, that's exactly the same as the El Paso proposal. We're interconnecting with them at Topock, which has interconnections with TW, PG&E. We're actually adding compression there to be able to take gas from the SoCal System, and using our Mojave Line, which touches their storage interconnections, and route all the way back down to Ehrenberg.

So, it actually does provide exactly the same as the north-to-south project, again at a significantly lower cost and, more importantly, a known cost rather than an unknown cost.

But as was pointed out in SoCal's direct testimony or, excuse me, data request responses, they did note that this past winter that even if they had the north/south project, because of the lack of storage it wouldn't have helped them to get gas down to the Southern System.

The Southern System actually had no issues because of the fact that they had baseload contracts on

El Paso's South Main Line. Which, today, they could go out and do just as well. We have actually an open season posted for South Main Line capacity, and open capacity can go anywhere.

So, I think that's -- I think Gregg hits a good point that they pin storage as an important criteria, but it isn't the only one. And I think all of the pipeline projects do give them access to the same points, at a much significantly lower cost.

MR. RHYNE: Okay.

MS. MUSICH: Just to be clear on that, it wasn't that we didn't have enough gas in storage. We weren't getting any supply into the system. The northern receipt points weren't getting any supply on those days.

And the way we're proposing to handle that is we do have another application before the CPUC for the low OFO, as Silas talked about, and that would bring supplies into our system.

So, yeah, the problem wasn't with storage. It was with the interstates and no gas coming in from there.

MR. PEDERSEN: Ivin? Norman Pedersen, SCGC. I'd just like to jump in and actually agree with, on the one hand, Anthony, Gregg, and on the other hand with Beth.

They're making a very good point. Anthony started out making the point. During this last winter we had two major adverse weather events. One was at the beginning of December, one was at the beginning of February. And folks in this room are very familiar with those two events.

Very importantly, the baseload contracts, and the memoranda in lieu of contracts that we had in place solved the problem for the Southern System. We had supply being delivered into the Southern System.

The problem was deliveries into the Northern System, plus stress on the storage systems of SoCalGas.

And so, the problem we had in both December, of 2013, and February of 2014, was in the north. And this leads us to, really, what I think SCGC is most concerned about, and that is the question as to whether we really need build options, as opposed to contractual options, such as the MILC, such as the baseload contracts.

And, very importantly, we're happy to see -- we're happy, very much, thank you Energy Division, for getting approval of the advice letter on the firm discounts out.

We know have, for this winter, another tool in the arsenal to deal with the Southern System reliability issue.

MR. RHYNE: So, Norm, that actually brings us to, I think, the next question quite nicely.

Which is, okay, so the discussion to this point has been about physical solutions to the issue.

But, Norm, your initial comments earlier, and now, again sort of raise the question of are there non-physical approaches that could solve this? And I think, Norm, you had suggested that.

And I know at one point, in fact SoCalGas had suggested, had made a filing about having a minimum delivery requirement into the Southern System, and has withdrawn that proposal, you know, in favor of this physical solution.

But how might those non-physical solutions sort of factor in to the eventual sort of solution to the overall problem here, in Southern California?

MS. MUSICH: I think we look at those as more shorter-term solutions. I can tell you that in the February 2011 curtailment situation there was no gas to be had out of El Paso, at any price. And we ended up curtailing the Southern System in that situation because there was issues upstream of our system.

And so, that's our concern that we have is tying that entire Southern System to one receipt point. You know, and that's an example of we think the pipeline, where we can get not only the storage gas, but all those northern receipt points is a better solution.

MR. RHYNE: So, sorry, you say that the gas wasn't available at any price.

MS. MUSICH: Yeah.

MR. RHYNE: My understanding was that there was gas available, but customers weren't willing to pay the price.

MS. MUSICH: I'm talking back in February 2011.

MR. RHYNE: Of February, I'm sorry.

MS. MUSICH: Going back to that situation.

MR. RHYNE: Thank you. Yeah, that --

MS. MUSICH: Because there was some well freeze-offs and that was when all of Arizona and New Mexico was having problems, and all the way back to Texas.

MR. RHYNE: Right.

MS. MUSICH: And so, there just wasn't an ability to get any gas there.

MR. RHYNE: Okay, thank you.

MR. PEDERSEN: And it's very important, Ivin, to distinguish between the February 11th event -- the February event in t 2011, which was the freeze-off event, from the December 2013 and February 2014 events. They were very different situations.

And the 2011 event was what I was referring to earlier as the force majeure event on the El Paso System. Yes, there, there were well freeze-ups on the El Paso System. There was a faltering of delivery on the El Paso System into the Southern System. We did have 200 million cubic feet a day, approximately, of curtailment.

I think, is that right, Beth?

MS. MUSICH: Yes. But, you know, the core customers in New Mexico and Arizona, they were curtailed, as well. There just wasn't any gas.

MR. RHYNE: Right, thank you. Just I needed the clarification to make sure we knew which event we were talking about.

Yes?

MR. PEDERSEN: But while we're on that 2011 event, Beth did throw it out there. And what I'd like to point out, we've gone back and we've taken a look at freeze-up events. Freeze-up events can happen in various regions at various times. Sometimes they happen up in the Rockies, sometimes they happen down in the southwest. They happen in different regions.

But statistically, it looks like they are something like a 1-in-30 year event.

So, if you're just focusing on freeze-ups, and you're focusing on a $720 million project, you know, you have to ask yourself are you really going to build that project for a 1-in-30 event.

And, additionally, if you're -- if your answer is, yes, then the Commission's answer could be, yes, at least for the core.

Well, there are other solutions that we've pointed out that could be put into place.

MR. RHYNE: So, the discussion here, I think has focused to some extent on, really, this Southern System minimum. But there may be other issues in play.

And I want to sort of shift -- and, actually, the good news for the Energy Commission is we don't have that responsibility of making that final determination as to which of these alternatives are the best for the State. But the discussion has been very helpful.

It does, I think, bring us to stepping beyond just this one issue and looking, maybe, a little out further than that.

The retirement of San Onofre has added some stress to the Southern California gas system, without a doubt.

You mentioned the expectation of 2,000 megawatts of new gas-fired generation coming into the system.

Are there any further plans or discussions about building natural gas pipelines to the coast, near the site where San Onofre now sits, in order to facilitate that new gas-fired generation facilities for electric reliability in Southern California?

And what about to Baja California, to take advantage of energy reforms occurring in Mexico that will open up the electric power generation and gas sectors?

And we'll start with Southern California Gas, but if any of the other panelists have thoughts, I'd welcome those as well.

MS. MUSICH: So, you know, we know there have been various proposals put in place to replace the San Onofre with -- I mean, not completely with natural gas, but partially with natural gas. And some of those have been looked at as being near where the SONGS facility was. But there's other proposals, in many other places.

But I can tell you, if a power plant were to be sited near San Onofre, then we would need some additional infrastructure to meet those needs.

MR. RHYNE: And how large a power plant are we talking about before you reach that sort of point where you think you need additional infrastructure?

MS. MUSICH: Oh, I don't know that I have that number off the top of my head.

MR. RHYNE: Okay. Any other thoughts, from the other panelists?

And what about -- sorry, go ahead, Norm.

MR. PEDERSEN: Well, I think you also mentioned deliveries into Mexico in your question.

MR. RHYNE: Right, and that was about what I was going to do. Yes, go ahead.

MR. PEDERSEN: Actually, something that we are very interested in is what is going on with Mexico. During the February -- excuse me, the April 16th, Natural Gas Stakeholder Workshops that you folks had here, at the Commission, there was a project by, I think Robert Kennedy, from the Commission staff, about exports to Mexico and about how he's expecting that they will tail off or even decline. He said that they would plateau around 2019 -- after 2019, around 3.5 Bcf.

And then he said they could either stay at the plateau or decline to around 2.5 Bcf.

But other things are going on in Mexico. And, you know, Sempra, of course, has the Costa Azul LNG facility in Mexico. Right now, it is a gasification facility designed to bring in imports. But, you know, it could be turned into a liquefaction facility.

And already, the FDRC has approved four liquefaction export facilities around the United States.

It could be turned into a liquefaction facility from which to export gas to other countries.

And that leads to options for all of these pipelines, the North/South Project, the TransWestern Project, the TransCanada Project, the El Paso Project, in which we were very interested.

You know, there should be no mistake about it, SDGC really does question the need for the North/South project to provide for Southern System reliability.

But as your question points out, other potential needs for pipeline infrastructure, and those needs could be to get gas to Mexico, both to serve electrical generation requirements and to serve other requirements, such as to provide gas to an export facility.

And, actually, something that SoCalGas -- well, something that Beth did at the April 16th -- at the April --

MS. MUSICH: I can't remember that far back.

MR. PEDERSEN: -- at the April 16th, Natural Gas Stakeholder Workshop, she presented a slide that actually was her slide 13. It seems like her slide 13 is always a very interesting slide. It was today and it was back on April 16th.

And actually, Silas, I e-mailed it to you. I was wondering, did you get it and can you put it up on the screen?

And what it shows, while the slide is popping up, it shows the North/South Project that would run from Adelanto to Moreno. I think Beth mentioned that -- or maybe it was Gwen that mentioned at the outset that, fundamentally, the SoCalGas system is an east to west system. But, you know, with the North/South Project, you'd have this North/South pipeline running from Adelanto to Moreno.

And then, actually, in their Pipeline Safety Enhancement Plan proposal, which was considered in the last triennial cost allocation proceeding, they proposed -- it was taken out of the case and it's reserved for a future application.

But they proposed a major line through San Diego County that would run from the Rainbow Station all the way down to South San Diego County. It would be a 36-inch pipeline. I think it's now called line 3602. And it's actually, the slide is up on the screen.

And you can see that we would have, with both line 3602 and the North/South Project, we'd have a cross-cutting line going north and south. We'd have a path north to south across the SoCalGas system which would dramatically reconfigure the entire, originally, east/west trending SoCalGas system.

And so, and now I'm -- I should say I'm probably not talking from SDGC’s perspective. But, you know, I’m a personal observer of the natural gas scene and so some of this is my personal observation.

But we could have a very interesting situation developing where we have demand developing in Mexico. Yes, electric demand, perhaps other demand, perhaps demand for deliveries to an export facility, and we have four, around this table four pipelines that would be able to take gas, one way or another, down to this new demand center in Mexico.

And it leads you, if you’re like us, you think you really don’t need the North/South Project to meet the Southern System reliability problem, and I’d like to get back to that at some point.

If you don’t need it for that, well, there might still be a point of having it on the platter, in the mix.

And if that’s going to be the case, maybe the way to approach it is to have a let-the-market-decide situation, kind of like we did back in the early 90’s, when we had the PG&E project, which became line 401, the Kern River project, we had a variety of projects being proposed.

So, there are -- your question points out that while there’s the discussion about the Southern System reliability problem, there are other potential needs for additional infrastructure and there may be other mechanisms to getting that infrastructure in place.

MR. RHYNE: Thank you.

Would SoCalGas care to comment on that at all?

MS. MUSICH: Just that the pipe that he's talking about, line 3602, would only meet the needs of San Diego. It's not designed to bring gas into Mexico. Yeah, it's sized exactly for the San Diego needs.

MR. PEDERSEN: And we could discuss that. It would be designed to loop another line, which would be a 16-inch line. After the looping was completed, the 16-inch line would be pressure tested, then brought back into service, so we'd have a 36-inch line and the 16-inch line both going into San Diego County. And there is a question as to exactly what the deliverability at that point would be into South San Diego County.

But that is all reserved for a to-be-filed application at the CPUC.

MS. MUSICH: It's certainly not what SoCal and SDG&E were contemplating.

MR. RHYNE: Okay, thank you.

So, our next question starts to speak to other risks that are outside just the reliability question. So, in constructing new pipelines what risk factors, in the Southern California Region, for this panel, such as sea level rise, impacts and seismic activity are being considered in siting and engineering these proposed pipelines? Not just SoCalGas's, but the other proposed pipelines.

And with the uncertainty posed by climate change, how are your companies and suppliers accounting for that risk?

Not everyone at once, please.

MR. SANABRIA: Well, I know for the Kinder Morgan project, for looping our Havasu, we're actually are already planning to loop it as part of an existing expansion with another customer.

So, we're just looking at actually upsizing our project in order to accommodate SoCalGas. So, based on that, we've already started to look at those issues.

The nice thing, again, about ours is it's a brown field. We already have a pipeline there. We have a history of operating there for probably close to 60 years, so we're well-aware of any issues that we will be facing on that.

MR. RHYNE: Thank you.

MR. RUSSELL: As far as TW is concerned, you know, with our project we would be utilizing a lot of existing right of way. And again, similar to Jim's proposal that, that's not using existing right of way, is going to very sparsely populated areas. Do not think we're crossing any fault lines.

You know, in our mind, the big risk around this project is probably cost escalation. And what we put forward is something that Energy Transfer would look to take on that cost risk escalation.

So, in other words, the proposal we've put forward to SoCalGas is this is the 20-year term that we're looking to recover our costs over. And the deal that we strike, when we cut the contract, as it relates to facility cost, is what that deal would be. There would be no escalator. Energy Transfer will bear the in-service and operations risk with that.

MR. RHYNE: Thank you.

MR. PEDERSEN: Ivin, your question, I think -- Norman Pedersen, SDGC. Your question gets into, I think, some environmental phase at the CPUC. As I'm sure you know, the CPUC is the lead agency for the North/South Project and there's an energy -- there's an environmental phase. A CEQA phase is going on before the Energy Division.

MR. RHYNE: Certainly.

MR. PEDERSEN: And something that we would look forward to raising in that environmental phase, in the

CEQA portion of the proceeding is why are we building a pipeline, a gas, a major gas pipeline that's going to have a service life of 60, 65 years, or longer, when the State has committed to the policy of reducing greenhouse gases by 80 percent, by 2050.

So, your question does raise a critical issue that will have to be addressed in this proceeding, and that is what is the wisdom of customers expending, I think I said earlier 720 -- it's actually $620 million. $620 million in direct costs currently projected on a project where we've got another State policy that's heading the opposite direction, and that's the direction of decreasing the consumption of fossil fuels, emitting fuels in California.

MR. RHYNE: Thanks, Norm.

Jim, I think you had something to add?

MR. SCHOENE: Well, we don't have a great deal of concern over rising sea level risks.

(Laughter)

MR. SCHOENE: If we have that, then everybody else has got a big problem before we do.

With respect to seismic activity, we've already collected -- you know, the literature is full and that's actually where you go, first, to investigate seismic issues.

The biggest thing a pipeline can do is to identify fault lines, put in heavier-weld pipe at those fault lines.

But moreover, to design its system to detect pressure loss in discrete segments and simply automate the shutdown of the pipeline. And I think that's true of every pipeline, I think, no one would argue that point.

MR. SANABRIA: Tony Sanabria, with Kinder Morgan.

To go back to Norm's point, I think that's one of the issues that differentiates the three alternative pipelines from SoCalGas's is ours have distinct end terms of 20 years.

Where our project, they would contract for it, at the end of 20 years it would be over.

As noted by Norm, and a lot of the literature, California's looking for a lot of renewables, a lot of changes. No one can predict what will happen, but committing to a 50 or longer-year-term project versus a 20-year term, and at the end of that 20-year term there is the right to renew it. So, if you need it for longer, you can, but you're not obligated, which is a big difference from, I think, the North-to-South Project.

MR. RHYNE: Okay, thank you.

Beth, I think you mentioned that you might have someone who can speak to that.

MS. MUSICH: We do. David Buczkowski. He’s walking this way.

MR. RHYNE: And if you’ll just make sure that the microphone is turned on, the little light should be on there.

MR. BUCZKOWSKI: Can you hear me?

MR. RHYNE: Yep.

MR. BUCZKOWSKI: Well, thank you for the opportunity to talk, a very interesting discussion.

My name’s David Buczowski, I’m the Senior Director of Major Projects for the Southern California Gas Company.

You know, some of the risks that we consider, that’s a good topic because, really, to identify risks are really how you define the project’s scope and really come up with whether the project cost is known or unknown.

And we’ve certainly spent quite a bit of work over the last year and a half doing that for this project.

The biggest risk factors that we’ve considered, have been considering are third-party dig-ins, seismic activity, landslides, erosion, wash-outs, similar to the consideration that El Paso TransCanada and TransWestern have mentioned.

We've actually done quite a bit of work on this. We've done seismic and geological studies to look at where the fault lines are. This is standard business, really, in California and most of the United States.

There's lots of engineering solutions for addressing seismic type of activities. Strength of pipe, flexibility. Also, what we've been doing is related to our pipeline safety work. I know, without talking about it here, but it's putting in automatically shutoff valves at either side of a fault crossing.

With respect to climate change, that's a real good point, probably with respect to all the alternatives, rising sea level isn't really an issue where our pipe is either between 1,000 feet or 4,500 feet in elevation.

But, certainly, climate change, additional rain, more intense rainfalls, meteor type of events are a major concern. We've studied those and scour studies looking at where you have, say, a wash. If you have intense rain in the mountains, that could cause a washout or erosion of a pipeline. And we look at those events and make sure that the pipe's got a significant depth to avoid any sort of erosion or conditions, with the respect to that. That’s my comments.

MR. RHYNE: Thank you.

So, we’ll get to the last question before we open up to any questions from the audience. And this is, this last question is meant to sort of shift gears mentally.

The proposals on the table really reflect a more traditional natural gas/fossil fuel supply through process, which has served California well for a number of years. But as mentioned, California has a number of goals that focus on renewable energy. One of the factors involved in that renewable energy goal is renewable biomethane.

So, are there any thoughts from members at the table about how biomethane might fit into any of these infrastructure reliability solutions for the Southern California system?

MS. MUSICH: Well, I think we’re always looking at ways to have those kind of technologies input into our system, so we’re very open to it.

MR. RHYNE: And I’ll take it from the silence on the other end of the table that there are no more comments here.

Okay, so with that I’m going to take a -- or we're going to open the floor to the members here in the audience. Are there any questions for the panelists related to the Southern California System infrastructure?

Okay, see none, I will look over to our folks running the WebEx. Are there any questions from online participants?

All right, so we unmuted everyone, so if you have a question now is the time.

All right, so we're not hearing any questions. This concludes our first panel. I believe next on our agenda is lunch.

So, we're running just a little bit ahead of time. We're about ten after 11:00 now. I look to Silas on logistics, how do we want to run this?

MR. BAUER: Well, it mostly depends on our next group of panelist's ability to start early.

MR. RHYNE: So, next up we -- after lunch we are scheduled to have a couple of presentations, which we could do now. We have the California ISO and Silicone Valley Power.

If they're both here, I'll look -- yeah, I see Silicone Valley power there in the back.

And so we have Greg -- or Brad, I'm sorry? No.

So, I would suggest maybe we invite Silicone

Valley to give their presentation and after that we can break for lunch. That will get us at least a little bit ahead and time us a little better with the normal lunch hour.

MR. BAUER: Okay.

MR. RHYNE: So, with that I will thank the panelists, as our presenter comes up. Thank you very much for your participation.

MR. BAUER: Thank you, Ivin.

MR. KENNEDY: I'm Robert Kennedy. I'll be the moderator for this afternoon's panel discussion.

At this time I'd like to introduce Steve Hance, before he begins his presentation.

Steve is the Senior Electric Division Manager of Resources at Silicon Valley Power. Steve has been employed at this company for 20 years. And has worked on the wholesale side of the business, and in procurement, and in scheduling of the electric and natural gas supplies, contract negotiations, resource planning, and power trading.

Over the past few years, Steve has expanded into carbon allowances, RECs, and capacity markets.

He also spent time as the Division Manager of Generation, with responsibility over operation and maintenance, over gas-fired and hydro-generation projects.

MR. HANCE: Thank you. Good morning, instead of good afternoon, since I got to be a little bit early.

I'll give you a brief overview of our utility. The City of Santa Clara, or Silicone Valley Power is a POU serving Santa Clara. We've got approximately 52,000 customers, 490 megawatts of peak demand, 3,125 gigawatt hours of annual generation.

We're a fairly high-load factor city due to a large amount of industrial and large commercial customers, at about 73 percent, and 90 percent of our sales go to retail customers, such as industrial and large commercial.

We're also a load-following, metered subsystem, means we still operate as a vertically-integrated utility within California, as opposed to selling off our thermal assets or generation assets in acting as a merchant.

On the supply side, we've got 900 megawatts of nameplate capacity. About 300 megawatts of that comes from large hydro, 200 megawatts from wind resources, about 20 megawatts of solar resources on the utility side, we also have quite a bit more on the customer side, 300 megawatts of gas-fired generation, a small about of geothermal, small hydro, a little bit of coal, and some landfill gas, as well.

On the natural gas-fired generation side, we've got our Donald Von Raesfeld Plant, commonly called DRV. It's a combined cycle plant, about 147 megawatts of nameplate capacity, made up of to 6,000 turbines and a steam turbine. It operates at base load at about 122 megawatts. It has incremental duct-firing of additional 25 megawatts. The heat rate at base load is about a 7,800 heat rate unit. The incremental duct-firing is about a 10,000 heat rate unit.

We also have some 1980s era simple-cycle peakers, commonly referred to as Gianera Units 1 and 2. They're a 25-megawatt, 15,000 heat rate units.

We participate in the Lodi Energy Center Project, developed by NCPA. Our share of that entitlement's about 72 megawatts of the 300-megawatt project. Its heat rate's about a 6,800.

We also have a small cogen plant. It's a 7-megawatt plant and it has two, old Alison 501K engines, about three and a half megawatts, each, that produce exhaust heat that uses steam that goes to a neighboring paperboard manufacturer.

We also have an interest in the Lodi and Alameda simple-cycle CT turbines operated by NCPA, very similar to our Gianera units, 15,000 heat rate. Our share of that project's about 31 and a half megawatts.

A little more details on some of these projects. The simple-cycle CTs, very high heat rate. The capacity that's typically bid into the CAISO markets is non-spin, very rarely operate. Energy's available to the CAISO in other emergency conditions, even though it may be bid into their market, through terms and conditions in our metered subsystem agreement.

Gianera units, the last significant run was during the Metcalf Substation event, for voltage support in the South Bay Area. I think we ran for about three days following that event, I think the two immediate days, and then the following week on a higher heat day when voltage started to sag.

Gas for these units, we typically don't procure any gas in advance of an issue or an order to operate them. We wait for the ISO's instructions. If they were to call on them for non-spin, it really would be difficult to forecast ahead of time whether a 15,000 heat rate unit is going to be needed to run for emergency needs.

Our cogen facility, because we have a steam house, we typically operate that in a base load mode, depending on what that steam customer's needs are. We usually will shut that unit down when they don't have a steam demand. It's self-scheduled with the CAISO and it's typically a price taker based on its locational marginal price.

The Lodi Energy Center, this plant operates as a merchant in the ISO's markets. NCPA operates the plant. It provides energy, spinning reserves, regulation up and regulation down into the electric market. It became commercial in 2012. It typically operates as a cycling or a peaking unit, where it's up and down on a daily basis, usually one start on a day. We do get some consecutive day dispatches from the ISO. I think we're seeing a few more of those recently, with the lack of hydro, than we have in the past. But we expect it to operate around a 40- to 50-percent load factor on an annual basis.

Gas is purchased because it operates as a merchant plant on a daily basis, usually before 0700 in the morning, before the ISO energy awards are out, and then there's incremental or purchases-for-sales that are made after that, once the ISO's energy awards are known.

NCPA also has a third-party agreement that manages their gas balancing needs, where they're required to give a forecast of their demand around 0700 to them, and then arrangements to buy or sell gas through that balancing agreement, that agent.

Our Donald Von Raesfeld Power Plant, just to break up the monotony of all tech slides, I put a picture in there for everybody. It provides local reliability of our system, voltage support. I think I talked about the peaking capacity, 147 megawatts.

This plant became commercial in 2005, with a total cost to construct of about $175 million. It has a small gas pipeline lateral out to one of PG&E’s local transmission mains.

It’s operated by SVP. Gas is typically procured at the PG&E’s city gate under annual, monthly, and daily contracts.

We also have a third-party agreement that provides daily and monthly gas balancing services.

The plant operates on daily economics based on a generator-specific total allowed peak price, and its marginal cost to generate power based on the PG&E’s daily city gate index, plus it’s O&M costs, and any transport costs.

During average to wet hydro conditions, our plant operates similar to the LAC plant, where it’s more of a peaker. And during dry hydro conditions that we’ve seen the last couple of years, we’re running more of a base load mode.

It also provides load following services to the

MSS.

Gas demand is currently easy to forecast since the project is self-scheduled versus bid into the CAISO markets, just because we've seen prices on a daily basis making this plant economical to run, as opposed to bidding it, we're just self-scheduling it.

Because we are -- we normally would do our load following for our load-following metered subsystem with hydro resources, due to the lack of water we will typically use our thermal resources to balance our load in real time. This causes some error in our daily forecast burn.

The normal gas burn's about 23,000 MMBTUs a day for this project. The PG&E 2015 gas rate case may cause a dramatic shift in DVR's current operation. The proposed rate case calls for a backbone-connected, or LT-connected generation, differential in price per MMBTU of about 90 cents. That difference equates to a six to eight dollar difference in marginal costs between equivalent heat rate plants.

I think we're seeing, in that rate case, a forecast that a lot of the gas throughput that's currently going to LT-connected plants to actually shift to going to backbone-connected plants, and a little less operation from LT-connected generation.

Our gas balancing agreement, we've entered into one of these for a couple of reasons. As far as existing staff, it would be nearly impossible for SVP staff to actually stay within our balancing requirements because we would have a very small pool, with a lot of deviation.

Being part of a larger pool allows us to have a little bit more flexibility.

It does require SVP to provide the balancing agent with a monthly forecast. In a monthly forecast we give them 30 or 31 days of what we expect our daily burn to be. And then on a daily basis, at 0700 we give them a forecast of what our next day's expected burn's going to be. It requires notification to the balancing agent of any intraday adjustments, if the unit's forced out of service, or if we're deviating from what our day-head forecast was, we have to true that up with them. It usually requires the sale or the purchase of incremental gas from the balancing agent.

The balancing agreement also allows SVP to bring third-party-procured gas to their pool, so we aren't obligated just to procure our gas through the balancing agent. We can contract with Shells, and JP Morgans, and any other gas seller that we have agreements with. They nominate that to the gas balancing agent's pool.

And then on a daily basis, after we give them our daily burn forecast, any imbalance between third-party supply is trued up or cast out with that balancing agent at the midpoint of the city gate index.

The significant differences between forecast gas burn and after gas burn identified after seven o'clock on the gas scheduling day almost always work against the generator. That typically means that the gas market's a little bit constrained because we're all running a little higher than we thought, and we're paying index plus when we're buying gas. And we're almost always selling gas at index minus when we have to sell it.

Gas scheduling versus electric scheduling, and here we're talking more about the actual scheduling of the gas versus the procurement. These markets don't always or they're not necessarily aligned. Gas scheduling takes place in their own nomination cycles, or energy scheduling is on the wet preschedule calendar. Usually, that's identified a year in advance. You schedule around holidays, you schedule gas on weekends, usually on a Thursday for a Friday/Saturday delivered product, and then on a Friday for a Sunday/Monday delivered product. Where the CAISO markets run on a 365-day-a-year, where bids are due at 10:00 in the morning and awards are known at 1:00 p.m.

CAISO market observes neither of the gas scheduling or the electric power markets on weekends, since gas trades as a Saturday through Monday block that almost always runs into a little bit of a problem when you're operating units as a peaking unit, because you have to buy gas as a three-day block, and usually sell back the Saturday and Sunday gas at a slight loss.

On the gas procurement side, we procure our gas, as I said, I think earlier, at the PG&E city gate as the delivery point. We procure gas as firm under a standard NAESB agreement. By buying it firm under a standard NAESB agreement is still subject to diversions in the PG&E's gas system. Not always considered a force majeure event in that case.

The only time it's force majeure is if there's actually interruption of firm transport. That puts the gas deliverer or whoever we've procured our gas from in a situation where if they want to use as-available transport, they can. But they can still face liquidated damages if they fail to supply.

Gas delivery performance from our third-party providers, in their event that there are firm curtailments, requires them to prorate our gas on a firm basis, which means they have to curtail all their non-firm customers, first. And then they can't cherry pick their firm customers based on the procurement contract price. So, if we buy gas at $5.00 and somebody else bought gas at $7.00, they can't curtail ours in favor of the higher-priced contract.

We currently, under contract, have about 32,500 MMBTUs a day of physical gas that's to be delivered.

Here's a nice graph of our 2014 September burn forecast or actual burn forecast, and our 2010 actual burns.

You can see back in 2010 it was a much more normal hydro year in California, where our DVR plant was typically operating as a weekday peaking plant, and then shutting down on weekends, and a little bit overnight.

And in recent operations we're running at almost a flat base load of 25,000 a day.

Gas procurement concerns. For the most part, our gas burn forecasts are due to the balancing agent at 7:00 a.m. We usually have to forecast what we're going to burn about six hours in advance to know -- or in advance of knowing what the ISO's awards for that generator may be.

This is more of a concern when we're in that 2010 scenario of higher hydro conditions, or if we're operating the unit more as a peaker.

Gas trades on ISE Monday-Friday. I think I talked about this a little bit. The CAISO markets run seven days a week. In the 2010 scenario this made it much more difficult to forecast weekend gas burns. Around some holidays, we're typically scheduling gas or procuring gas three to four days ahead of knowing what the ISO energy awards are going to be.

Overall, you know, when you are taking a discount or paying a surplus for gas, on situations like that, it doesn't really become much of a concern, the price is relatively minor unless there's actual OFO orders out.

When OFOs are issued, the gas price to create your bid at the ISO can be drastically different than what your actual procurement cost of gas is going to be, depending on if your forecast of what the ISO is going to dispatch you at is incorrect.

Potential solutions that we see is there might be some way to align the energy scheduling, gas scheduling and CAISO markets, where we could at least observe the same holidays or schedule the same blocks of gas and energy on the same days.

There's maybe a potential to go to scheduling gas an energy one a seven-day-a-week basis. I think the Intercontinental Exchange trades both financial and physical gas. There might be the possibility to have the Intercontinental Exchange operate on a seven-day-a-week basis and have an electronic trading platform for that type of physical gas.

There's also the option of owning storage rights. Typically, an expensive option. It's probably most needed for units that operate as peakers and dispatch very little, and have a hard ability to capture that cost in your bid to the ISO.

Reliability concerns. Non-core gas for electric generation can always be diverted to core customers. This always could put the ISO in a situation where those of us that are generating would have to curtail our production, either by taking forced outages, or just not generating. It could be put in the situation where the ISO then needs to call on other generation. If it's thermal-based, it could be as high as 15,000 heat rate plants that are bidding operating reserves into the market.

Those 15,000 heat rate plants more than likely don't have gas nominated to their facilities.

PG&E diversion procedures call for prorated diversions of their firm customers. They don't look at generator heat rates, their location, the electric transmission or any sort of coordination, that I'm aware of, with the CAISO or other California balancing authorities.

There are also issues with the credit received from diverted gas. If you have firm supply and it’s diverted, you receive a credit from PG&E, but that goes to the transporter, not necessary the generator. If you’re buying our gas at city gate, the charge for OFO penalties isn’t necessarily aligned with what the ISO’s real-time energy prices are if you don’t generate your costs.

Additional reliability, units claimed for resource adequacy in the ISO have a must-offer obligation into the market. You’re required to bid these resources, but still face potential diversions.

Gas-fired units offering operating reserves, especially non-spin, have no obligation to actually have physical gas available, should they be called on. And they’re most likely to be called on when the gas system is actually stressed.

And that’s it, thank you all.

MR. BAUER: Thank you, Steve.

I noticed that Brad walked in. And Brad is the other person who’s going to give an opening presentation in this natural gas electricity coordination presentation.

I’m thinking that we may want to have lunch and then come back and do that, unless everybody from the next panel is here, but then we'd go significantly over the lunch hour.

And I'm seeing shaking heads. So, we'll do lunch now, and then reconvene at 12:45. And Brad will start out and then we'll move into our panel questions. So, I'll see you all then, thank you.

(Off the record at 11:30 a.m.)

(On the record at 12:45 p.m.)

MR. BAUER: We're now going to start with the second half of the opening presentations of the Natural Gas Electricity Coordination Panel.

So, we're going to start with Brad Bouillon, from the California ISO.

And I'm going to turn it over, now, to the moderator for the panel, Robert Kennedy. So, take it away, Robert.

MR. KENNEDY: All right, thank you, Silas.

At this time I'd like every panelist to come on up and take a seat, along right here, please.

I didn't have a chance to do this earlier, but I just wanted to kind of tee up this issue for the broader audience, to provide them context.

Again, the title of this panel is Natural Gas/Electricity Coordination and Effects on Natural

Gas/Electricity System Reliability.

Currently, natural gas-fired generation is the largest source of power in the State of California, making up roughly 44 percent of total generation.

However, new State, Federal environmental policies, along with changes in generation output from both nuclear and hydroelectricity have the potential to affect future demand for natural gas for power generation, and may change the role of current and future natural gas-fired generation facilities in California.

These changes, as they interact with current market rules and current infrastructure makeup may have an impact in the way natural gas is reliably supplied for power generation.

California resides at the end of the supply chain for natural gas and currently imports about 90 percent of its total natural gas needs from outside of the State.

Today, for our panel discussion, we have assembled a distinguished panel of experts to discuss challenges and opportunities in the area of natural gas supply for power generation in the State of California.

I would like to introduce Brad Bouillon, Director of Regional Operation Initiatives at the

California Independent Service Operator.

Brad currently works, his work is focused on regional operations initiatives, concentrating on gas/electric coordination, standards review, performance management, and bench marking.

He also acts as the operational interface for State, regional, and national topics, as related entity interfaces.

Brad has been with CAISO for more than 17 years, and worked in the energy industry for over 25 years.

Brad is presenting a presentation right now.

MR. BOUILLON: Good afternoon, everyone. The presentation I have is kind of an introduction into the panel discussion. It's higher level and I'll be talking about some of the aspects of the topics that we have -- are expecting to cover, coming up.

Currently, CAISO works quite extensively with the gas companies in sharing information and working towards coordinating our efforts in ensuring both gas and electric system reliability.

At any given time, you know, the gas generation in California, under CAISO's jurisdiction or control, could be as much as two-thirds of the market makeup, so it has a significant impact in our reliability overall.

Towards that end, we share information pursuant to a nondisclosure agreement. One of the questions that's arising today is a discussion of the FERC NOPR. There's a formal FERC initiative out, talking about information sharing. And that information sharing effort is fairly defined. If you read it, it's defined.

Our NDA approach is much broader and it allows us to share a lot more information, and be more proactive in our communications relative to following what FERC is heading towards.

So, we consider the FERC piece valuable, but what we're doing is broader and we're fortunate to have that in place, in our relationships.

We send hourly estimated gas burn profiles to the pipeline companies each day. Those are based on our day-ahead awards, allowing them to understand potential impacts for the following day.

This is an initiative and we've been doing this for a while. It's based on our day-ahead awards, like I said, and it does come out, typically, early to midafternoon each day, for the following day, giving enough advance notice to the gas companies to see if they have any reliability concerns that we could talk further about.

Along the communications side, we actually do hold quarterly meetings to discuss outage impacts, and also biweekly status calls.

The quarterly meetings are formal outage discussions. We actually do -- this year we actually held a long-term outage meeting in October, and that outage meeting goes until December of 2015. And we actually do ask the gas companies for outages they have scheduled or are known at that point in time, so we can incorporate them into our electric planning.

So, we do look at the gas outages and then we look to coordinate related electric generation outages into those timelines to the best extent possible, minimizing total down time or disruption to those two systems.

And we actually under -- we have actually reached out to the gas companies to talk about rescheduling some outages. And while it's expensive and a long lead time, we have seen flexibility and support from the gas companies.

Like I said, I'm very proud of our relationship. It's very, I would say, accommodating to where we can, where it doesn't jeopardize reliability, we work together extensively.

And then on cold days, we conduct morning conference calls. We actually conduct them in the middle of the night and early into the morning trying to be as ahead as possible with our floor-to-floor communications. Which means our real-time shift supervisors actually leading that call and we're talking to their counterpart on the gas side, in real-time about challenges for the day, forecasts for the day, any changes in the forecast from what we sent in the burn rate reports, and any additional information that's come online, like outages that could affect where the gas is going to flow.

You know about, I just referenced the FERC, the discussion on communications. FERC has increased their focus on gas and electric interdependence. They review actions to improve cold weather grid performance and they're kind of working for updates on a quarterly basis on gas and electric coordination.

I have appeared on panels, and as I know some of our gas companies have, as well, with updates to FERC in the spring and fall time frame. And now, they do formal quarterly updates, which you have to provide written status updates to them.

They are proposing reforms to improve coordination of the gas and electric scheduling timeline. That was referenced in the prior presentation, as well, in talking about challenges in gas and electric scheduling.

I've got another slide to talk a little bit about that, a graphic of that.

And then the discussion on sharing information is that last bullet and that's the piece that FERC is focused on. It's been at a request of one of the ISOs, actually two of the ISOs to help formalize the communication and information sharing.

And I can tell you that across the country communication and information sharing is not necessarily consistent among ISOs. The relationship of ISOs and their gas companies does differ from ISO to ISO.

Just taking a step back and talking about differences between gas and electricity, you know, this is common sense to most people in this room, but it may be new to some newer people.

And that is that, you know, gas and electricity don't flow at the same rate. Gas flows at 25 to 30 miles an hour, maybe a little more depending on who you talk to or the line structure and design.

But electricity essentially flows instantaneous, very close to the speed of light. And so, it's a big difference in deliverability when you're trying to transmit energy that's in gas form in electric form. They're not apples-to-apples.

As a result in timing, we have different true-up methodologies on our two systems, and we have different timelines associated with the scheduling and that true-up methodology.

Okay, now, here’s a busy graphic. I tried to put as much information one slide as possible.

(Laughter)

MR. BOUILLON: And what happened is I started out with four slides and I figured out that I’d be up here talking a lot longer and really trying to convey a message.

Which, essentially, this slide shows on the top part is the electric scheduling timeline. On the bottom part, below the green horizontal line, you have two lines. You have an orange and a blue. And the orange is the current timeline for gas scheduling and the orange is the current timeline for electric scheduling. So, it’s an orange and orange means current.

And then blue, and I’m not an expert, is the way I interpreted the recent FERC order on the gas armitization (phonetic), coming out of the NAESB process, their proposed scheduling changes show those timeline differences, okay.

I don’t know if I have a laser pointer, but it’s hard to talk about this -- if I take it away from the mic, I don’t think people on the phone will hear me.

Thank you. Okay, so if you look at the way the market is designed, you see on the electric side you have a 10:00 a.m. This is our market close, so that's when they start running the electric market.

And the 13:00 is our market publishing, when we publish our day-ahead results.

So, it's consistent with the previous presentation when we were talking about how the electric schedules get published. They get published at 13:00 and they start on the next day -- oh, excuse me, on the trade day. So, they start on the trade day.

And on the gas side, when you have your timely cycle at 9:30 in the morning. So, you look that you close your timely cycle, and then you start your day-ahead market. So, you have your -- you know what you paid for the bulk of your gas when you're entering the day-ahead market.

And then, when you close the day-ahead market, you have your evening cycle so that you can actually buy makeup gas based on the difference.

Now, this works in a market where you have a predictable day-ahead structure. Meaning, currently our day-ahead clears 98 to 99 percent of our real-time energy needs.

So that means when your hear real-time, and all those people working, and you see the picture of our company on the floor, working, they're balancing one to two percent of the electricity.

You understand? So, it's more like fine-tuning, as opposed to big swings in reliability. So, it makes the market much more predictable.

So when you have that, if you look at the way we have our structure, it's unique to most ISOs in North America. Because most ISOs in North America, they want to give you your day-ahead awards, and then they want you to go into your timely cycle and buy your gas.

Okay, so it's different, it's not apples-to-apples.

But if you look at the way that we're -- the timing that was being proposed and the changes, so your timely cycle closes at 15:00 and 19:00. And I apologize, because everything's Central Standard Time on the gas side, and I think I've got these times right, so I'm pretty close.

So, you look at the 9:30 goes to 15:00, and the 16:00 goes to 19:00, so it shifts it later in the day.

From an electric side, the closer you get to real-time, the greater your accuracy of your forecasting, but the less lead time you have to get generation on, so there's a challenge in how you're going to do that.

So, you look at how that time shifts back more towards the trading day. And then these are your intraday cycles within the trading day, so that you have an eight o'clock, and then a 15:00.

And then the proposal underneath B is to have three intradays, an 11:00, a 15:30, and a 20:00, which is eight o'clock at night.

And so, the intraday cycles allow the ability to buy makeup gas in a formal cycle, depending on timing and liquidity of the market, obviously, but the ability to get that makeup gas, if it exits, to make up any shortfalls. Or in theory, I guess, selling the overages if you're not balancing or netting in that condition.

So, if you can see, again, they don't match. It's not apples-to-apples.

On the ISO side we tried to fit between the timely and the evening nomination cycle. I'm not saying that's the best solution. We talked to our participants and that was the desired outcome, so we matched that.

So that when you look at these changes, just assuming for the sake of argument that the blue lines become the change, then the ISO would have to decide whether we're going to shift our day-ahead to fit, again, between the timely and evening cycles, or whether we're going to become consistent with the East Coast and we're actually going to try to close our day-ahead before the -- and giving people time to buy gas in the timely cycle, based on your day-ahead awards.

Okay. But the big point and the takeaway that I wanted to talk about here is that there's a lot of -- they're not exactly the same. And some of it is by design and some of it is by history on how it works.

But in general, you know, we're trying to come together and trying to make it work. And I think it will be one of the questions that I think will come later on the panel.

The final observations I had on this is that this is something that's relatively new, a couple years old, but it's changing month over month. As you get new information, as you get new conditions you actually adapt and you refine your processes.

And I won't go into a lot of detail but, you know, the challenges we had on February 6th, I think the one thing we can agree is that, you know, we took a look at how we communicate and we tried to figure out what we did right and what we did wrong, and tried to improve on that.

And I think that's the goal of anything we're doing in this relationship here is that as the market dynamics change, as you get more gas-fired generation, as you get faster-start gas-fired generation, as you get more solar penetration, whatever those changes are, you know, those result in different demands on the gas system and different demands on the electric system. And that's where we have to work together to make sure we balance that reliability objective.

Again, the focus is on the future system process communication improvements, meaning that we're looking forward as we're going along through this process and effort, and that it is ongoing.

I do have room for questions, but I think these will kind of carry into the panel discussion. Robert, right, I think that's fair and then we can talk. And then there's obviously an open forum, I think, for questions at the end as well, right, so we can get it in then. Okay, thank you.

MR. KENNEDY: Thank you, Brad.

At this time I'd like to name the members on our panel and introduce those that have not yet been introduced.

We have Brad Bouillon from CAISO. Steven Hance from Silicon Valley Power.

Nick Schlag, Senior Consultant from Energy + Environmental Economics. Nick joined E3 in 2009, after completing his Masters of Science and Civil and Environmental Engineering at Stanford University. He worked at E3 and has focused on the practice areas of renewables and emerging technology, and resource planning.

In 2014, Mr. Schlag led a study investigating the adequacy of natural gas infrastructure in the western interconnection to meet evolving needs of the electric sector, accounting for changes in operational needs resulting from coal plant retirements, and growth of renewable generation.

We also have Catherine Elder, Practice Director for Energy Resource Economics, from Aspen Environmental Group.

Catherine directs the Energy Resource Economics practiced at Aspen Environmental Group, where she manages the technical support Aspen provides to California Energy Commission on electricity and natural gas issues.

Ms. Elder also joined Pacific Gas & Electric, and worked on both federal and state level industry restructuring in the late 1980s.

In 2010, she authored *Implications of Greater Reliance on Natural Gas for Electricity General for the American Public Power Association.*

We also have Gwen Marelli and Beth Musich from SoCalGas, and also Roger Graham from PG&E.

Before I get started here, I'd just like to remind everyone to please state your name and your affiliation before you speak.

And just to give you an idea how this is going to go, these questions aren't meant to be rigid in nature. You're the experts. I encourage you to speak, give us the benefit of your knowledge and experience.

If I feel that you're getting off topic a little bit, I'll kind of rein everyone back in.

And also, I'd like to remind everyone there will be time at the end for the audience and those online to ask questions.

The first question, just to get things started, and I would encourage all panelists to kind of weigh in to get us started here. Just looking at how things are currently set up here in California, from the perspective of the panelists what areas have California successfully coordinated natural gas supply for use in power generation.

Maybe to help you with this question, think about some of the issues that have arisen in the northeast and some of the problems that have occurred in that area, some of which haven't occurred here.

Maybe you can speak a little bit to that. And keep in mind this is the current makeup. We'll be talking about forward-looking questions later in the discussion.

MR. BOUILLON: Brad Bouillon, California ISO. I think that some examples of where we successfully coordinated gas supply includes the part of my presentation on the gas burn rate reports, which helps show, in a forward-looking perspective, the anticipated gas burn rates by region or sub-region for each of the gas companies that we have a nondisclosure agreement on file with. And that's provided in a daily basis.

And I think that that communication helps change a reactive relationship into a proactive relationship where people can ask questions based on forecast.

I think that our emphasis on improving forecasting and getting our day-ahead more accurate towards the day-ahead, towards the contribution into real-time has helped also provide stability and predictability going into real-time for both the electric and the gas side when we talk to you guys because our numbers are more reliable that we're sending you guys.

MS. MARELLI: Gwen Marelli, SoCalGas. I just want to add to what Brad said, is we've seen increased communications from the operator level all the way up to the senior management. And I think not only on a daily basis, but very proactive, ahead of the season, so we really appreciate that.

MS. ELDER: I'll jump in and get away from the microphone a little bit here.

You know, in that February 2011 cold snap, and the curtailments that happened occurred were really a wake-up call. The ISO, since then, hired Brad Bouillon. There was not a Brad before that.

And the kinds of discussions and the detailed information sharing on the operational level that are happening now, were not happening then.

When those power plants had to be curtailed in that February 2011 curtailment, folks in Folsom were surprised. And today they wouldn't be surprised. So, that's a huge -- I think that's actually a huge accomplishment.

MR. GRAHAM: Roger Graham, with PG&E. I think one of the things that works well for us here, in California, that hasn't been the case in the East Coast, is that we grew up as a local distribution company, serving gas-fired generation for essentially most of the history of our company. So, I think we're a lot more familiar with a lot of the issues that come with that.

I think I'm also going to talk a little bit about the next question, you know, what doesn't work so well. Is, I think Steve mentioned it earlier in his presentation, just about the liquidity in California. Or at least the gas markets seem to work, you know, sort of Monday through Friday and they trade the weekend in a block. And Brad mentioned there's intraday cycles, even evening cycles, but they're not very liquid. You know, not much gas is traded.

If you haven't bought your gas by 7:00 a.m. Houston time, you know, there's not much left.

So, I think there needs to be a lot more liquidity in the later cycles and being able to split up the weekends.

MR. SCHLAG: This is Nick Schlag, with E3. I certainly don't want to discount the specific coordination that a lot of the other panelists have noted. But I also wanted to emphasize or elaborate a little bit on one of the points that Roger just made.

Which is that in California you have, really, one of the only examples that I can think of, in the United States, of a deregulated electricity market, with a really large gas fleet that has gas infrastructure that's, for the most part, appropriately sized to meet the needs of not only the consumptive end uses, but also the electric generators.

And here, it really helps to compare and contrast California to some of the other areas around the United States.

In the rest of the west what you have is you have a lot of vertically integrated electric utilities who receive service from interstate pipelines, but because they’re vertically integrated they can make the choice, as an integrated utility, to subscribe to firm pipeline capacity. And a lot of them have made that decision.

And so, what you have in those instances is a single entity choosing to pass the cost of pipeline capacity onto their ratepayers.

In California, we have a much different model. We have the deregulated electricity markets, with utilities purchasing power from the Cal ISO. And it looks a lot more like the model for electricity that you see in the northeast, where there have been a lot of problems.

And I think the big difference or one of the big differences that you can highlight between, say, New England or New York, where you’ve seen prices jump up to $100 per MMBTU over the past couple winters, is the fact that in those markets the model is still one of the firm versus interruptible subscription-to-pipeline capacity.

And just because of the simple economics, a lot of those generators, operating in those environments, make the decision as a profit-maximizing entity, not to subscribe to firm capacity.

Now, in California we have different planning standards and design criteria. And Beth and Roger could speak more closely to what that model looks like.

But at the end of the day, we've come up with a scheme where we pass some of the cost of pipeline capacity onto the generators that ultimately require that capacity.

And I think that, in and of itself, is a big success in California.

MR. KENNEDY: Would anyone else like to weigh in?

MR. HANCE: On part two, this question where we're talking about things that might not be working so well, we do have a significant portion of the gas fleet that can run on dual fuel. But I don't think there's really a convenient way of bidding that availability into the market right now, and there is restrictions on when we can run on dual fuel. That is a little bit prescriptive, there has to be either some sort of an emergency, and that's not really well-defined in the air permit rules.

MR. KENNEDY: Thank you. Well, it seems like everyone beat me to the punch on the second question.

Would anyone else like to weigh in on the second question, which is in what areas has California not been successful in coordinating natural gas supply for use in power generation?

Anything more to add in that area?

Okay, let’s move to the next question. And this is delaying more on a regional basis. And I know we’ve covered some of these issues this morning.

The issue of synchronizing natural gas supply with demand from gas-fired powered generation can vary based on regional circumstances.

And in the case of Southern California, the shutdown of SONGS, in 2012, created a unique challenge.

In light of this challenge, what do you see as the major issues facing Southern California with regards to the interface of natural gas supply and power generation?

So, I think I’ll direct, maybe Beth or Gwen, you can start us off on this question.

MS. MARELLI: Sure. You know, the decommissioning of SONGS really highlighted to us the interrelationship between natural gas and electricity.

And then the curtailments this past winter really showed us how much natural gas is part of electricity reliability.

So we learned a lot and, you know, as a result of the changing marketplace and the dynamics.

MR. KENNEDY: Maybe you can talk about how these things are going to occur in the context of meeting our RPS Renewable Portfolio Standard of 33 percent renewable sales by 2020. There's going to be more ramping requirements in the area to back up renewables. And there's a lot of things going on with OTC being phased out. I mentioned SONGS isn't going to be there. Can you talk a little bit more about that?

MS. MARELLI: In terms of -- yeah, so, well it's a new marketplace. We're going to see different things happening, the ramp up requirements, the quick requirement when the renewables are not available. What's going to happen with the quick starts on our system and how natural gas -- how natural gas will have to be, I guess, the backup fuel until more battery or other means for providing that backup power will be available.

MR. KENNEDY: Would anyone else on the panel like to weigh in on this question.

MR. BOUILLON: This is Brad, from Cal ISO. You kind of asked two questions, one further down, too. So, I'll kind of get started on it. So, the loss of SONGS, SONGS was a baseload, 2,200-megawatt non-gas-fired unit. So, you ended up with shifting 2,200 megawatts somewhere.

And, you know, we've had a lot of renewables implementation. We've had a lot of variable resources come online, and I think even more than that 2,200 megawatts since that time. I mean, significantly more.

But this was a baseload unit, so you've got to make up the time where those variable resources are not producing, and that's where you lean on the gas fleet.

Which kind of carries into Robert's second question about, you know, how does that address the ramping or the flexible requirements?

And I think that there's another aspect, and that is that when SONGS was generating, there was a major switch yard that's tied to SONGS. Probably the most, the largest, most complex switch yard in our entire system for re-dispatching electricity throughout the Southern State.

And that switch yard, without SONGS, is virtually idle. I mean, there's almost nothing going through that switch yard relative to what it was before, when SONGS was generating.

And the fact that SONGS gave us 2,200 megawatts was valuable. But the fact that you could ship it in different directions, at any point in time, was the real value. And that's what you've lost. Not just the generating megawatts, but the fact that you don't have any generation there in that switch yard to actually begin to use the asset to switch energy to where you need it.

And so, from a SoCalGas perspective, my comment is that it makes more demand locationally-specific for the gas fleet, for reliability, that we did not have before. And that's the challenge that came out of the loss of that unit.

MR. KENNEDY: Just to add on that, the way the SoCal system is comprised, isn't it true that some of the natural gas-fired generation is connected to the pipeline system more at a distribution level, rather than through major backbone pipelines?

MS. MUSICH: Yes, some of it's on the distribution. I think you're probably talking more about like on the L.A. Loop, which is a transmission system, but it's below a city gate, so it's operating at a lower pressure.

Different than PG&E, where I think most of their electric generation is located on their really backbone lines.

And, I mean, to that issue about the ramping, if you get too many of those clustered together, especially in that L.A. Loop, or that kind of area, you know, you can have issues where the pressure starts dropping pretty substantially if multiple quick-start units come on at the same time.

MR. KENNEDY: It's true that when you have these smaller diameter pipelines, I mean there's more competition with other sectors, such as residential and commercial, correct?

MS. MUSICH: Sure. Yeah, obviously, you know, the bigger the line, the more pack that you have in the line and the more ability you have to deal with swings in the load. So, yeah, as you get to the end of the system, you know, if you're at the very top or the very bottom of the system, you have less ability to deal with rapid changes in load.

MS. ELDER: There, I turn myself on, turn myself off, you know.

(Laughter)

MS. ELDER: Caty Elder, with Aspen. You know, I was going to pick up this point that Beth, Robert just got Beth to make which was to say, you know, that you really have a different configuration north versus south, and the relationship of the large-diameter pipes, and the positions of the power plants, themselves.

And we don't tend to think about that. We tend to think, oh, we've got gas-fired generation with PG&E and we've got the gas-fired generation on SoCal, but they're really different systems in that respect.

The other point, to pick up what Brad was making the point about, that switch yard at SONGS. And I remember being at, I think it was NCPA's annual conference, just about two years ago, right after the August or September outage in San Diego, that was caused by the flip of the switch, or whatever it was on the APS substation over on the Colorado River.

And I remember Berberich being at that conference and saying had it not been for SONGS and the gas-fired generation in San Diego, we would not have been able to bring that system back from a cold start as quickly as we did. And so, that was really important.

The irony is that the best place, obviously, to replace that generation would be to put a gas-fired power plant right there, at the beach at SONGS. That's not going to ever happen in my lifetime, I think. I've heard that the Navy wants the land back, among other problems that might present themselves.

The other problem is, is if you actually look at a detailed map of the Sempra system, there's not great gas access at that particular location. You've got it at Carlsbad and Encina, but you don't have it north of there, right along the beach.

So, we'd like to make use of that infrastructure, but it doesn't look like we're going to get to.

MR. KENNEDY: I've also heard that SONGS provided a lot of inertia and aided with power quality. Can you speak a little bit on what role natural gas-fired generation going to play in terms of providing the transmission support between L.A. Basin and San Diego?

MR. BOUILLARD: I can speak a little bit to that. I mean, you've seen some changes. There's been some synchronous condensers installed and there's a -- and then you still have to have baseload fossil, with inertia behind it to maintain stability out of voltage.

And I think that you see a mix of that in the Southern System, but it's not as clear cut as you had in the past, when you had the reliable baseload of a nuke.

I'm not saying good or bad, but you have to make that up somewhere because you have to manage the energy output, the actual piece, plus the voltage stability for local support.

MR. KENNEDY: I'd like to move along. We

touched on the Northern System and out the PG&E system is comprised a little bit differently than SoCalGas. Maybe we can talk about that in the context of how hydroelectricity, that's been tailing off with the drought, and what upcoming challenges there are as far as implementing renewables.

Can someone from PG&E speak to that, please?

MR. GRAHAM: Well, I think the good news was, as the hydro production went down, there was a lot more renewables. We didn't see nearly as much gas-fired generation come onto the system this year, as we have seen in prior dry hydro conditions. And I think that's a lot because there is that renewable resources that have filled in.

We've done a quite a bit of studying, looking at these issues of ramp rates on our system, as well. Everything we've studied at this point leads us to believe it's not going to be a problem.

And the reason that that has been is that the ramp, the really extreme ramp rates that we have seen for electric gen occur in the afternoon, and not in the early morning. If there's some technology or something that happens with these renewables, where we start seeing large ramp rates in the morning, and gas-fired generation coming on coincident with our residential morning peaks, that would definitely cause significant problems on our system.

So, that’s something that we keep looking for to see, you know, if charging electric vehicles or, you know, wind generation -- you know, you forecast this stuff out there and you think this is how it’s all going to unfold and, you know, when you get there it probably will be different.

But kind of looking forward to things that could have an impact on our system is if we start seeing more peak in the early mornings.

MR. KENNEDY: You mentioned the ramp rate. It’s true that you have a lot of power generation connected to a larger diameter backbone lines. Can you talk a little bit about that and what role that plays in balancing gas supply for power generation?

MR. GRAHAM: Yeah, so on our system, you know, like SoCal’s, we have some really big, long line pipelines that go out to the State border to bring the interstate supplies into our system. And they’re very large, very large pipelines, to the extent that a single power plant on them, you know, it’s kind of noticeable to our gas controllers but, nah, not really that interesting, you know, they are so big.

But if you get those same power plants off into the local transmission system, it becomes a big problem.

PG&E has had a differentiated rate between what our end-use customers pay, if they're directly connected to the backbone facilities versus what they pay if they're connected to the local transmission system.

And that has incented power generation, the new fleets that come on after, you know, in the 2000s, to site on our backbone system, which is a lot more -- there's a lot more flexibility there on how we serve them.

MR. KENNEDY: And there's less competition for gas on those pipelines because the most competition occur on the smaller diameter distribution lines?

MR. GRAHAM: Well, there's the same competition because the backbone system is used to supply --

MR. KENNEDY: To supply, right.

MR. GRAHAM: -- the people who are buying gas for the residential customers, the commercial customers, and the industrial customers. But it's just that their capacity is so much bigger that that competition doesn't, you know, really have a significant impact.

MR. KENNEDY: Sorry, I'm going to shift gears a little bit right here and talk more about some of the market rules.

The polar vortex occurred in the winter of 2013 and 2014, and caused unseasonably cold weather outside of California, and as a subsequent -- in a subsequent rise in demand for gas to heat homes and businesses, higher demand outside of California resulted in higher prices in those markets, which prompted increased gas loads away from California.

This led to supply shortages and one day in February curtailments on electric generation facilities in California.

These events highlighted possible problems with the way electric generation fuel costs are recovered and the way natural gas is purchased during extreme weather events.

What could be done to avoid such risk in the future?

And the way I see it is just really highlight the need and Brad, you mentioned this, coordination and communication between pipeline operators and also Cal ISO.

I know there’s some amendments being proposed to change the way costs are recovered to allow electric generators to put OFO bids -- to work OFO penalties into their bids.

Maybe Brad, you can talk about this a little bit.

MR. BOUILLON: So, a couple of things have changed and I'll talk a little bit about it seems like when you looked at competition for gas, originally, it was relatively local, then it kind of expanded to sub-regional, then it went to regional

And now, with the infrastructure, it looks like you're competing for natural gas across the country. Meaning that if you have prices that are high enough in the northeast, people will leave our system because they can somehow make money getting that gas east.

And I think that that has really highlighted the importance of incenting or reflecting the need to keep gas in our area for reliability.

And I think if you looked at February 6th, in particular, it wasn't particularly cold in the northeast on February 6th. January was the worst month.

The FERC report on solar vortex actually excluded California. I don't know if you read that, but in one of the pages California was not in that report for the polar vortex.

But February 6th was a day, if you remember I believe that was the Super Bowl Parade for the Seattle Seahawks, and if you watch how they were dressed, it was like 23 degrees in Seattle, which is like unheard of.

And what you saw was an entire Western U.S. cold snap. And so the competition for the gas, while it may not have been going east, was competing amongst the whole Western U.S., and I think that created some challenges.

Now, it was a combination of events that led to the problem. One was the gas price run-up was very short, meaning it happened -- I don't want to say instantaneous, but it happened over a very narrow period of time and our markets couldn't reflect those prices.

So, one of the tools that you're talking about, better reflecting prices, was the ability to say how do we incorporate that change in fuel cost. And that's an initiative that is in process right now.

The second one was, when you're talking with the gas companies how do you get away to say, if you're really working for reliability, how do you make sure that you can get a generator on that is going to be beneficial to the gas side and the electric side. And I'll say beneficial, let's say neutral to the gas side and beneficial to the electric side, meaning it does not harm it.

And that was that initiative that you had referred to, Robert, on the OFO piece. And there's a call on that, on Friday.

But I can tell you that looking at a condition, where you're in an emergency like February 6th, like you were talking about, a reliability event where we're actively communicating with the gas companies and we're talking. While people saw that as a Southern Cal challenge, we were actually actively talking to PG&E, as well, because it's a California challenge. Which is, how do you keep the lights on across the State? Not just in the southern area, but how can we balance generation to get the megawatts electrically to flow, to keep the lights on by backstopping it in PG&E's area, for example.

And that got into discussion of the OFO piece you were talking about. And a way to address that is to look at conditions where we're mutually discussing resources, or mutually agreeing to resources that can run without damaging the liability on the gas side, while putting out megawatts that help the electric side.

And remember, this is reliability, and not markets, the way that we operate 99 percent of the time.

MR. KENNEDY: I know, as you mentioned, there were problems getting gas into Southern California. In some cases, I know there were curtailment issues, and Cal ISO wasn't notified. And Cal ISO saw that a facility went down and so they dispatched a couple more to make up for that.

And that resulted in a greater draw down on gas, on the pipelines.

What's being done as far as coordinating the discussions between that?

MR. BOUILLON: I think it's fair to say that, you know, this was an anomalous event, because we communicate all the time.

In this one event, what happened is I think you guys saw a sudden draw down and you were reacting to it. And our system re-dispatches automatically. So, if you lose -- that's the big deal is from the electric side, our system is automated.

So what happens is, if we lose a gas unit, and let's just not say it had nothing to do with February 6th. Let's say that Encina had a compressor problem and it tripped their whole unit offline, our software would do the exact same thing, it would re-dispatch automatically, based on our merit stack, and give the -- and bring on all the units that were economic based on the needed output. That's all automatic and it happens instantaneously.

So, on February 6th, when that happened, we actually were talking to you guys within, I believe, 6 or 9 minutes of that event. I mean, it was very quick. While it wasn't proactive in that case, it was within 6 or 9 minutes, and then we talked proactive the rest of the day.

So, I would say that that could be a lesson learned. But I also want to say that, you know, it was not like we weren't talking to each other. We were doing a pretty good job of communicating. It's that, you know, working on it collectively and collaboratively, in a prospective approach going forward is something that we've really stressed.

MR. GRAHAM: I just want to add a little bit to this. One of the things at PG&E, that we constantly struggle with is how tight to make our balancing procedures.

You've got to remember that only about a third of the gas in our system we own, and only about a third of the gas in the system goes to electric generation. There's two other very large markets that operate on our gas system, you know, the residential market, small commercial, as well as the industrial market.

And, you know, some of those markets are maybe more predictable than the electric gen.

We don't want to really clamp down on our balancing rules by making everybody balance within, you know, five percent every single day, because it's very disruptive to the other markets in the system to require that, when it's not needed, you know, 80 or 85 percent of the days of the year.

Our system can naturally deal with the natural diversity among those markets very easily.

But, you know, how do you then sort of quickly switch and require more stringent requirements for bringing gas in to match your use.

And, you know, we use operational flow orders. Though, you know, they're imperfect, mainly because we have to call them the day before, you have less information. Our market not only wants us to call it the day before, early the day before. When the gas trading is done, you know, at 7:00, 8:00 a.m., you know, they want to know for the next day that we're going to have a problem.

You know, we're not that good a forecasting and, you know -- but we hate to -- we've had this discussion of, you know, maybe it's time to go to daily balancing for everybody, just make that just the norm. Well, that's very disruptive for all the other markets, disruptive for the electric generation market 80 or 90 percent of the days when, you know, the systems can accommodate it.

So, that's a tension that's out there that needs to be kind of recognized. And, you know, how tight do you want to make things.

MR. KENNEDY: That kind of led into my next question, referring to FERC's Notice of Proposed Rulemaking to adjust the gas day. They're proposing a 2:00 a.m. California time --

MR. BOUILLON: Yeah.

MR. KENNEDY: Right. And for the day ahead, it would start later at 11:00 a.m., right?

MR. BOUILLON: That's a possible outcome. Because we'll, a stakeholder that -- assuming that happened, what you're talking about, we're going to actually stakeholder whether we want to continue our design of having it in between the timely and evening cycle or do we want to shift it before the timely cycles start -- or close, excuse me, timely cycle close.

MR. KENNEDY: Okay. And it's also proposing going from two to four intraday nomination cycles.

I'd like, if the panel, if they can kind of weigh in on how you -- because I'd like to hear both on the natural gas side and on electricity generation side how you feel that would affect your business.

MR. HANCE: This is Steve Hance, with Silicon Valley Power.

I think from an electric generation side it's kind of a chicken-and-egg issue. If you move the timely nomination cycle, what will likely happen is gas will likely trade later. You know, will you actually have a good index price for your physical gas you want to purchase to use in order to bid into the market or, you know, do you leave it alone, where it is now, where you've got a good index on where gas trades on most days, but then you have a six-hour lag before you know where your awards are.

And it's kind of -- you know, there's that six-hour window between the ISO market and where gas trades now. You could probably tighten up a little bit, but I think by moving the timely cycle to 2:00 in the afternoon, now, you may cause gas to physically trade in kind of the western markets at a point after our bids are due, and then we're going to be kind of flying blind on what we use as an index price for our gas generation.

MR. GRAHAM: That's interesting whether the trading will actually change. I know that was FERC's hope in moving some of the cycles later. But, again, nationwide gas-fired generation is even smaller than one-third of the market.

You know, there's other people, other participants in the market, like the LDCs, buying for their residential customers, who are going to get out their early. They want the gas, they're willing to bid up the gas. And if the electric gens aren't there early, you know, if they want to try to trade that gas a little bit later, you know, other market participants are going to go in and buy it.

So, I'm not sure it's going to really move gas trading any later. I mean, it kind of trades on Houston time and it's moved slightly earlier than 8:00 a.m., as the early bird gets the worm, right, the trading in Houston has move to slightly before 8:00 a.m., maybe even as early as 7:00 a.m. Houston time, now. It's been moving earlier, not later, even though the timely nomination deadline hasn't changed.

So, I don't think that's going to change much, myself.

PG&E is quite concerned, though, with the proposal to change the start of the gas day. Moving that to the middle of night, PG&E believes, is really a dangerous thing to do. There's safety implications and I think there's reliability implications, especially for the West Coast utilities.

As we reconfigure our system each day to go from, you know, the interconnects, whether it's gas coming into the State, whether it's being gas injected for storage, or withdrawn, a lot of those changes are manual operations. We actually have to send people to the field to start and stop certain compressor stations. The same with some of the storage facilities that require manual operations. Trying to do those things at 2:00, 3:00, 4:00 in the morning, you know, just isn't the right time to be doing those type of critical operations in your system.

MR. KENNEDY: Just to piggy back on that question, FERC is also proposing some other measures to address this issue. Some are other types of transmission services and cost allocation schemes. They're even proposing an electronic bulletin board for the natural gas system.

Would anyone like to weigh in on how you feel that might affect operations out in California?

Go ahead.

MR. BOUILLON: This is Brad, from Cal ISO. I mean, I can kind of talk about how I think it can work, but then there's the reality of how people are actually doing business, how they're transacting.

And looking at the proposed changes, the concern I have is how much of it is actually going to improve, and I'll be selfish, out here on the West Coast, how much is it going to actually improve what we do? How much is it going to actually make it more liquid and give you better opportunities, as a consumer, to say, okay, I can buy gas when I need it, without having to pay 33 percent more, or buy it before you know what your nominations are to figure out what you have to match to, what you have to nominate to and match.

And from my perspective, you know, I looked at the timing, I looked at the gas day start. We're lucky because the gas day is based on Central Standard Time, so we gain two hours over whatever time they put. And so, in this case, they put 4:00 a.m., which is 2:00 a.m. which you hear PG&E's discussion on, from Roger.

But, you know, right now, we have two hours, actually three hours of a shorter gas day into the next day than New England does, and that's one of their concerns.

And so, everything that pulls forward, pulls forward by the three hours.

I see the timing of the intradays as the valuable piece to possibly offset the gas day change if they're liquid enough. And that was another concern is, you know, if you have liquidity, if there's active participation in those markets.

Because if you offer an evening intraday cycle that is after the evening load pull on the electric side, you give people an opportunity to make up their gas and carry it into the next day. Thereby, in my opinion, mitigating the effects of that day carry-forward. I'm not saying eliminate, but let's just say minimizing it.

And so, if you had an active cycle that was late in the evening, like is being proposed under that NOPR, and people are participating in it, I think you could make it less of a concern, the gas day start.

And so, to me, that's one of the things I'm interested in exploring. And I've discussed that with the other ISOs under a group that is an ISO RTO Council Group, exploring what are alternatives, and what can you focus on.

And again, if you've looked at the testimony that I've provided, Cal ISO is neutral as to the gas day start, meaning we're not -- we're agreeing to any of the gas day starts. Status quo we agree to, and we agree to everything up to the early start times. Because from an electric market stand point, the impact is negligible to us from that start.

MR. SCHLAG: Robert?

MR. KENNEDY: Go ahead, Nick.

MR. SCHLAG: I just wanted to add a few comments. I'm not going to comment specifically on the pieces of the NOPR, or its individual components.

But from my perspective, you know, the State's well on its way to meeting 33-percent renewables, and that's a big change. We can already see how gas generators are moving from sort of operating more on baseload or intermediate capacities to being used as balancing resources.

And what that means is there's more uncertainty in how gas generators might be dispatched. There's more variability in how they're dispatched.

And to that extent, the conventions of gas scheduling, and nominations, and things like that, they act in some ways to introduce friction between those two industries.

And so, for example, the idea of increasing the number of intraday schedule nomination cycles from two to four, again if they have sufficient liquidity, provides opportunities to correct for changing conditions with renewable output and to facilitate renewable integration.

And so, while I don't have sort of the be all/end all answer to whether FERC's NOPR is exactly the right way to go, I think it's really important to remember that at least investigating these types of changes can be a facilitator of renewable integration and help mitigate costs to ratepayers.

MR. KENNEDY: And that's a good segue into my next question. I wanted to talk about the intermittent, must-take renewable sources. And I know you looked into this quite extensively in your study, referring specifically to the duck curve that Cal ISO put out. We know that there will be a lot of minimum net load that would be met by natural gas-fired generation, and then a significant ramp in the afternoon.

Can the panel talk about what this will mean for the natural gas infrastructure, as far as its ability to meet these ramping requirements and to operate at minimum load and possible over-generation during the middle of the day?

And just what I'm getting at here, as we all know, we're going to need a facility back there that can ramp up significantly, and also in a short amount of time. And these are units that are going to be attached to natural gas pipeline.

I know there's been some studies that have looked into this. Can you talk a little bit about that?

MR. GRAHAM: For PG&E's system, the duck curve's not a bad deal. It actually provides some more time for our system to recuperate during the day for the winter draw. I mean, a gas system has a lot of flexibility and we carry, in our system, 4 billion cubic feet of inventory.

I mean, you know, the pipes, they're long and they have a lot of gas in them. And they can operate, at least on our system, between a fairly significant pressure range between the maximum pressure and the minimum pressure that we need to maintain to serve our customers.

And that difference, that swing in inventory is kind of a one-shot deal, though. It provides lots of flexibility, but once it's drawn down, you know, it can't be replaced until the demand that drew it down goes away. And so, it actually is somewhat helpful for our system that after we see the really large morning peak for our residential gas load, you know, to have a breather. The system pressures then come back up and then it's even a little bit easier to serve an evening peak.

The type of ramp rates we're seeing in the simulations are not a whole lot different than the ramp rates we see for residential load. I mean, it comes on quite quickly in the morning. You know, not a lot of -- especially in California we're not seeing a lot of furnaces, a lot of heating load at, you know, 2:00 a.m., 3:00 a.m., 4:00 a.m. You know, it's not that cold here.

But when people get up, they like a warm house and they turn on their heaters. And, you know, a lot of us operate on the same schedules, you know, plus or minus a half-an-hour, or an hour. And that ramp rate's pretty dramatic on our systems.

And, you know, our systems were designed to meet that. You know, grew up sizing our facilities to meet that very predictable ramp rates. But, you know, so luckily we have the facilities there that we can -- if they're not being used by the residential market, you know, can be used to serve the electric gen market.

MS. MUSICH: Yeah, I think it's locational-specific as to how that works. We do have a number of quick start units already on our system, including like an 800-megawatt peaker plant on the Southern System, of course.

But, you know, we've managed to deal with it so far. But, you know, we do get concerned depending on where it is on our system. And I think part of it is going to be a learning curve for our gas control, and getting used to seeing things where pressures are diving quite quickly, and distinguishing that that's a quick start coming on, and not a line break, or something like that. So, you know, or just realizing that eventually that straight downward pressure will bottom out and level off.

So, yeah, so I think it's educational and location-specific as far as for SoCalGas and SDG&E.

MR. KENNEDY: That addresses the ramping issues. Maybe you can talk a little bit about the intermittent issues.

You know, there's an opportunity to repack your lines during the middle of the day, when there's a lot of renewable generation. However, in the event there's overcast or wind generation goes down, can you talk a little bit about how that might affect the system?

Brad, I know there's been improvements in forecasting renewable generation. Maybe we can talk about that on the natural gas supply side, as well.

MR. BOUILLON: This is Brad. I'm trying to think of how to carry this from -- from Cal ISO's perspective, when you're looking at the repowering of generation, which there's a lot of it, including the once-through cooling, as the repowering starts for those.

People are typically repowering into these fast-start units that Gwen -- excuse me, Beth had just talked about. And that is that when they're repowering, they're going into units that draw really quickly on the system.

And that, actually, is consistent with the vision of California, moving forward with natural gas as kind of a backstop for renewables, and the variability of the gas has to be dynamic enough to adapt to those changes in those renewables.

So, I don’t necessarily see it as inconsistent. The challenge is going to be how do we accept it and integrate it into a solution that the gas side can work with that doesn’t jeopardize reliability on the gas side.

If you look at our solar ramp in California, we are about, I don’t know, just under three hours. I think it’s two and a half hours, and we make about 4,600 megawatts in about two and a half hours. And that typically shifts, obviously, throughout the year as the daylight sunrise times change.

But when you look at that and overlay that to the core piece that Roger talked about, which is how does core gas demand happen?

As you start to see the core come up on the gas demand, you start to see the solar ramp for parts of the year, so you actually see it helping. It actually helps on the gas side, in some instances.

But in the fall/wintertime, and particularly February 6th, for example, the solar was ramping out right in the middle of the evening load pull. And so, when you saw that you had, you know, a normal load pull, but then you also had that exacerbated because all your solar was coming off.

And back them I think it was like, I don’t know, it was 3,000 megawatts of solar, roughly. Now, it’s 4,300 megawatts right now, on average, that you’re seeing. And our high is in the 5,000 range, right at five.

And as you see what’s coming on, it’s going to become steeper and steeper as you see more and more decline off.

And the challenge, in my opinion, is going to be related to how do you carry that cutoff of the solar, because that’s our big player, to flatten that decline out so that you don’t have that challenge in your ramping.

So, I think we have to do a combination of things. It’s not just gas fast-start, recovering, and back-stopping the renewables, because I think the technology is there.

While its emissions has slowed California’s response a little bit, I think that helps the gas company to say, oh, it’s ten minutes to 100-megawatts per unit, as opposed to six minutes to 100-megawatts per unit. So, unconstrained, those units can actually make it. And you put them in series, you can go zero to 800 megawatts in six minutes.

And so, the ten minutes is great because we got a diversity in your fleet, we've got units that are already going to be online and they can fast ramp and be flexible in their operation.

But also, how do we make the renewables in a way, because the technology exists to actually help shave the peak, or to extend those declines so that you can actually work that in a way that balances better together.

MS. ELDER: To tag onto that, Gwen mentioned earlier storage, energy storage. And we're also talking in other forums about distributed renewables, about storage associated with those, but also time-of-use rates.

And so I think ultimately, not maybe in the next two years or three years but, ultimately, there will be a variety of tools to address these things. It won't just be reliance on gas to go up and down on the system.

MR. GRAHAM: You mentioned something there. PG&E's been looking at this issue about forecast error. It's very intriguing because we've seen across the different technologies, and across the different players even within the same technology having very different abilities to forecast. You know, whether there's wind generation that's going to happen, whether there's solar's going to happen.

And this is a big deal. As I mentioned, one of our flexibilities in our system is our system inventory, but it's a one-shot thing. And if it doesn't get replenished in a timely fashion, you know, you have to really start bringing on other resources, like gas storage and things like that.

So, it's important that people do forecast well. And as you get more options, that's nice, but you have to be able to forecast whether those things are going to happen. And it's because gas-fired, at least in the near term, is always going to be sort of the residual resource.

And if the forecast isn't right and you have to carry these imbalances from day one to day two, to day three, then the gas systems can really get in trouble. You know, that's when you really have to start really closing down on your operational flow orders, or various other things to get the system back into shape.

You know, I guess our systems are pretty flexible, but not infinitely flexible. And if you start carrying imbalances, you know, day after day, then the gas system will definitely be in trouble.

I think all the studies we did, with Nick and others, you know, assumes that as these ramps occur that there was gas coming in to ultimately repack the system.

But if that didn't occur then, you know, literally within a day or two you would be in trouble.

MR. SCHLAG: And I'll just add a few comments. This is Nick at E3. I know that the Cal ISO has made big strides in recent years, in renewable forecasting, and that's something that continues to improve.

And we have to remember here, as we continue to build more and more renewables, we get more and more geographic diversity. The more solar that we put in different parts of the State, the smoother that curve becomes on sort of a day-to-day basis, and the more easily it can be sort of predicted and forecast. That's an important thing to remember.

All of this, you know, there's a lot about the ramps that you see from these quick-start gas generators, but I think it's also important to highlight that there's a reason to ask those generators to ramp up quickly and that's because there are going to be large periods in the future where we're not calling on gas generation to produce much output at all.

So, while you have this increase in variability in the power sector, you're also going to have this overall decline in throughput in the gas system. The more renewables we have, the less annual energy we're going to get from our gas-fired resources. So, it's important to keep both of those things in mind.

And certainly, in this SoCal system, you know, there are places were quick-start units, specifically, when they come on the system will cause these large pressure drops. And it will be learning by doing to kind of get used to that.

But on a lot of other parts of other systems, both in California and throughout the country, as we see more and more renewables, it's going to cause decreases in throughput and it's going to create opportunities to move line pack around to provide flexibility.

MR. KENNEDY: In the past, pipelines are built to respond to increasing demand. Looking forward, there's a possibility that pipelines will need to be built to respond to increase supply reliability.

Can anyone on the panel speak to, basically, it's putting a value on reliability for supply. So, for example, I know there's increased demand of natural gas going to Mexico, and if there's more of a firm contract to send natural gas there that could impact supply to Southern California.

For reliability purposes, can you see possible changes and curtailments of practices, generators supplying to more firm supply of natural gas?

MS. MARELLI: Sure. It's Gwen Marelli from SoCalGas.

The idea of electric generation priority factored into curtailments is an intriguing idea for us. And, you know, our intent, when we're curtailing our gas system is not to affect electric reliability. So, we see that this could be a provocative idea to pursue.

MR. GRAHAM: PG&E, internally, has taken a look at this issue around curtailment priorities. And the problem that we ran into is that there are no other large loads out there, unless you're ready to disrupt the fuel market, the automobile fuel market. You know, are you willing to curtail oil refineries.

On our system, that's the next largest load and it represents, you know, something like over half the industrial demand on our system. You know, the rest of it's very diffuse and even that has, you know, implications. Large hospitals or noncore customers, there's lots.

You know, you look around and you say, yeah, we'd like to keep the electric system going. I'm sure we all like to have our lights on. But there just doesn't seem to be enough load in other market segments that don't have their own reliability issues for society, where you can go to, to curtail.

And as we've worked with Brad, I think you find that if the two systems can work together, which we have now have the tools to be able to communicate on a real-time basis, that at least so far there's always been enough gas. Sometimes not in the right place.

But the electric system also has some fair amount of flexibility in where they site their generation. And being able to coordinate those things on a real-time basis actually, you know, saves the State at numerous times, I think already, where you can say, yeah, maybe that generation shouldn't run. But you know, these ones over here, there's plenty of gas in that area of the system, so turn those on and shut that one down.

And, you know, Brad can do that across the entire State.

MR. KENNEDY: So, in effect it may be more costly to adjust curtailment rules as it is now? I mean, talking about some of the other sectors, commercial, residential, there's impacts there as well.

And Brad, as you mentioned, these curtailments are communicated with Cal ISO and exceptional dispatches are automatically done in those cases, correct?

MR. BOUILLON: Okay, I'm trying to figure out the question to me.

MR. KENNEDY: Well, I guess the first part of the question was directed at PG&E and SoCalGas.

MR. BOUILLON: Right.

MR. KENNEDY: And I think you already addressed the second part, as when these curtailments occur that's automatic, that's communicated with Cal ISO to do your exceptional dispatches.

MR. BOUILLON: Oh, okay. Okay, so let me start back a little bit. First off, we operate a market, so you have a merit dispatch order, you have bids in a stack. It's dispatched based on hierarchy of the bids. That's the way the markets work.

Now, under exceptional conditions, I think that may be where your question is headed, which is you're in a reliability condition, you have your markets running, but you have to augment that with exceptional dispatches, individual instructions to individual units to either balance reliability, for example, as opposed to running the market.

I want to set those two aside, okay, because we run a market, that's our operation.

And in a reliability situation to keep the lights on, you may do extraordinary items on an individual basis. I think that's your question, right, which is if you had that.

From our perspective, you know, we want to run everything through the market to the greatest extent possible. And so, when you look at opportunities and how to design it, we are working on tools to make it better. Actually, we are working on a couple of tools to make it better, where we can work on market solutions getting into some of these difficult conditions, where we actually are working better with the gas companies, and using market solutions.

So, we're actually adapting to these changes in the market and how it's worked. Whereas today, or last year, we used exceptional dispatches. And we've used them for years, that's not a new term. But we try to minimize the number of exceptional dispatches, obviously.

But what we're doing is actually trying to figure out why we're exceptionally dispatching, especially under reliability conditions, just seeing if there's market tools we can build to actually enhance our market to represent those conditions, and solve it using a market.

And that is something that we're actually trying to work on. It may not make this winter, but we're trying to get one in, in the next year.

MR. KENNEDY: Okay, at this time we're running towards the end of our panel discussion. I would like to open it up to any questions that we may have in-house here. Feel free to step up and ask the panel or -- yeah?

MR. PEDERSEN: Norman Pedersen, SDGC. Brad, about, I don't know, 45 minutes or an hour ago, when this panel was starting, you were talking about how, on February 6th, you were talking to SoCalGas within six or eight minutes.

And I kind of lost what you were talking -- what was the event within six or eight minutes you were talking to SoCalGas?

MR. BOUILLON: That was the very early condition where one of the gas-fired generation units was shut off. And so, we had re-dispatched around those lost megawatts. About 600 megawatts, I think, just as a ball park figure.

MR. PEDERSEN: Oh, so in other words, what you're saying is they declared -- I think on February 6th, and Beth, correct me if I'm wrong, it was about a 300 NMCF curtailment, right?

MS. MUSICH: Well, we had the Southern and then we had the rest of the system, so I'd have to add it up.

MR. PEDERSEN: The February 6th, we're talking about February -- we’re talking about February 6th, 2013, right? Not the February 2011 event, we’re talking about February 6th, 2013 --

MS. MUSICH: 2014.

MR. PEDERSEN: 2014, rather. February 6th, 2014, sorry. We had December 2013 and then we had the February 6th or 10th, 2014 event. And SoCalGas declared a curtailment of standby procurement service, which basically means that the customers have to get their burn to -- or get their deliveries into the system within 90 percent or more of their burn. That’s basically what standby curtailment is.

And then they also had a curtailment of some individual electric generators.

Now, when you contacted them, it was within six or eight minutes of the curtailment of standby procurement service?

MS. MUSICH: No, the emergency curtailment of the Southern System generators.

MR. PEDERSEN: Okay. Well, it wasn’t just Southern System generators, no, it was system generators. That was --

MS. MUSICH: No, the Southern System generators were in the morning and then it was the afternoon when the rest of the system generators were curtailed.

MR. BOUILLON: Right, my comment was we talked very quickly right after that first one, but we were proactive the rest of the day --

MS. MUSICH: Yes.

MR. BOUILLON: -- working together to make sure we balanced everything.

MR. PEDERSEN: Okay, so there was a curtailment, so you were talking to them within --

MR. BOUILLON: Oh, they called us, it was very --

MR. PEDERSEN: Okay, okay. And I'm trying to understand, so SoCalGas was determining which electric generators to curtail on the basis of the communications with the ISO?

MS. MUSICH: So, in the Southern System we did not -- we were unable to serve the needs of the electric generators, and so we had to go to an emergency curtailment that morning. And so what we did was one generator was pulled completely off the system and all of the other generators were asked to hold at wherever they were at the time that we called them.

MR. PEDERSEN: And that was declared under the standby curtailment rule or under rule 23?

MS. MUSICH: The emergency curtailment, yes, that --

MR. PEDERSEN: Rule 23?

MS. MUSICH: Yes.

MR. PEDERSEN: Okay, and so after that you coordinated with the ISO on the curtailment of electric generators?

MS. MUSICH: So, then that's when the electric generation moved to the northern part of our system. And as I remember, I think Diablo Canyon was down at that time, as well.

MR. BOUILLON: Yeah, there was a bunch of contributing factors to February 6th. But the piece I want to talk about is when we started talking, we were looking at gas reliability so we could maintain electric reliability.

MS. MUSICH: Right.

MR. BOUILLON: So, we were working together on that. And that's what happened starting from that initial communication, right after that specific unit was curtailed.

MR. PEDERSEN: And what Rule 23 enables you to do, to curtail customers on the basis of these communications with the ISO?

MS. MUSICH: No, it was an imminent threat to our core customers, so we did an emergency curtailment in order to save our core customers.

MR. PEDERSEN: Okay. And Brad, now back to you. You were talking at the very beginning of your presentation about NDAs you have, and you talked about NDAs with pipelines, and there was a point in your slide when you talked about interstate pipelines.

Do you have NDAs with -- you know, you're FERC regulated. Are you NDAs with FERC regulated interstate pipelines, or were you talking about NDAs, nondisclosure agreements, with the California local distribution utilities, you know, PG&E and --

MR. BOUILLON: Cal ISO has NDAs with both PG&E and SoCalGas. And then we have NDA's pending with Kinder Morgan and Kern River, which are both FERC jurisdictional entities.

MR. PEDERSEN: Okay, great.

MR. BOUILLON: I think that was your question, right.

MR. PEDERSEN: And just one last question. At the very end, Brad, you were talking about the FERC initiative to both change the definition of the gas day and the NAESB proposal to develop a new standard which would, of course, be subject to FERC approval for the nomination cycles.

And you were saying, both you and Roger were commenting on how it would be very helpful to have more liquid intraday markets. If we're going to go, for example to three intraday nomination cycles, as proposed by NAESB, it would be very helpful to have more liquidity in those intraday markets.

Wouldn't that liquidity -- I didn't quite understand you. Wouldn't that liquidity be more valuable if you had a gas day that ran to 9:00 a.m. in the morning, rather than just 4:00 a.m.

Because if you had a gas day running to 9:00 a.m., it would give you four more hours for gas to flow under, say, an ID-2 or an ID-3 nomination to get to customers?

MR. KENNEDY: Let me just interrupt, just to say this will have the last question and so we'll have to move on. Thank you.

MR. BOUILLON: I think my belief is that if you have liquidity in those intraday cycles it makes the gas day start change less significant.

I think that if you have truly liquid later day cycles after the evening load pull on the electric side, in particular, it gives you a lot more flexibility for makeup gas and balancing that I think would be very valuable.

So, I didn't really tie the two together directly, but I think the liquidity in that late day cycle gives you the ability that you've finished your evening load pull, you know your actual burns, 90 percent of your gas burns and you know where you stand the rest of the day, I think you have better flexibility in helping maintain reliability of both systems.

MR. PEDERSEN: Thank you.

MS. ELDER: And the big point, or question I think, Norm, is whether we'll get that liquidity. You know, if the traders still go home, or to the golf course, it won't do us any good to have another nominating cycle.

MR. KENNEDY: Okay, well, I'm sorry, everyone, in the interest of time we'll have to move on, now.

I would like to thank all of our panelists for participating.

For all of those still in the house, or online, that didn't have time to ask a question, please submit your questions and comments to the information shown on the slide. Thanks, again.

We're going to pause, now, as we prepare for our next panel.

MR. BAUER: We are now going to continue on California production and supply.

And our first speaker is going to be Leon Brathwaite, who is from the California Energy Commission and works in our Natural Gas Unit.

I do want to note we've had a little bit of attrition on this panel. And so, towards the end of the questions, we're probably going to open it up to the full discussion with the Natural Gas Working Group, and also to anybody in the audience who might want to take a stab at answering some of the questions that Leon's going to ask the panelists.

But for now, I want to introduce Leon.

MR. BRATHWAITE: Thank you, Silas. Good afternoon, everybody.

Of course, my name is Leon Brathwaite. I've been working here, at the Commission, for a very long time. Actually, when I started working here I used to have black hair. You can see that's changing now, right.

So, anyway, today I'm going to talk a little bit about supply and production. I want to focus a little bit on California, but I cannot do that without talking about the rest of the country, in particular the lower 48.

During our IEPR work -- IEPR work 2013, we developed three cases, three scenarios of our natural gas supply, production, and prices in the lower 48. This was a reference case. It was a low-demand/high-price case, and a high-demand/low-price case.

What we are trying to do is to capture the variation in supply, demand and price. Well, of course, California is linked to the rest of the country, to a very extensive pipeline network, and we produce about 10 percent of our own demand. So, that means 90 percent of the gas that we consume here, in California, comes from outside the State. So, whatever happens out there, will certainly affect us here.

So, it’s very important for us to understand how much gas is available and at what cost it is available.

So, if we look here, at our supply cost curve, these things actually go into the model. Now, the curve that you’re looking at right now, this curve, in particular, is not in the model. This is a composite of about three or four hundred curves that are presently in the model.

So, what I want to show you here is during our 2007 assessment, we came up with a blue curve. Then our 2011 rolled around, we came up with a red curve. And then we came up, in our 2013 work, we came up with a green curve. Notice the curve is shifting to the right. Which means we’re having more gas available, at lower cost.

Because if you look at that curve, you can see at $4.00, in 2007, you say, well, maybe about 600 TCF is available.

At $4.00, in 2011, you say, well, it's running close to 800.

At $4.00, in 2013, we see it's getting up around almost 1,200 TCF of gas available to us.

Please keep in mind that during all this time we are consuming, in the lower 48, about 20 to 23 TCF per year but, yet, the curve is shifting to the right and expanding.

We also looked at the reserve life index. The reserve life index is where we take all of the gas, all of the known reserves and we divide it by the current rate of consumption.

Now, during around 2000 it was about 54 years. About around 2008, that ran up to 87. By the time we got to 2013, we were at 112 years.

So, our current rate of consumption, we have over 100 years of gas available to us. A lot of gas, more than we know what to do with. So, more gas is available at lower cost.

The question then becomes why? Why is this happening? Well, of course, it is because of the development of the shales. Years ago we did not know how to access the shales. They were there, we knew there were a lot of gas in them, but we had no idea of how to access it.

But in the last 15, 20 years, as a result of the some of the work by George Mitchell, from Houston, Texas, well, he was really just outside Houston, he showed us by using hydraulic fracturing and horizontal drilling we can access the shales. And now we have shales all over, maybe in 31 states in the lower 48, and there may be five provinces in Canada, and seem to be expanding every day.

We have the Marcellus, which is probably the largest shale in North America, up in the northeast.

We have the Bakken, which is probably the most prolific shale right now in the lower 48, and that’s in the North Dakota area. This extends also into Canada.

We have the Barnett is probably the most developed. We have the Fayetteville, the Haynesville, we have the Eagle Ford down here, which also extends into Mexico. So, shale is all over.

But we also have shale here in California that have been identified, the Monterey in particular, but it’s not yet developed.

This was an issue that I was hoping that our panelists will discuss at some point in time, if it is possible to develop that shale here in California. It’s supposed to have quite a lot of reserves in there. But it's something we'll talk about later on.

So, as a result of our work we did a snapshot. And this is a 2025 snapshot. Now, we can do this for any year in our whole forecast horizon. We could do it for 2015, 2010, if we wish, but we did it for 2025, just to see what it looked like out there.

So, here we have the lower 48 and we have two main demands. We have end-use demand and we have exports. We have end-use demand right here running about 73 Bcf per day. And we have exports, and we'll talk a little bit more about that shortly. 8.4 Bcf a day of exports, that's what we expect in 2025.

Now, how is all of that demand satisfied? Well, that demand is satisfied by Canadian imports, about 12.7 Bcf a day, lower 48 production, 72.3 Bcf per day, and a little bit of LNG imports, about .2 Bcf a day.

So, this is how our supply and demand balance works in the lower 48. In a little while, I'll show you how it works for California by itself.

But I wanted to focus a little bit on the exports. Well, there are two kinds of exports that probably will be occurring. The first of which is pipeline exports to Mexico.

Right now, as we speak, there is growing demand in the power generation sector in Mexico. And Mexico has a significant amount of under-developed resources. So, what is going on right now is that many pipeline companies are proposing to build pipelines that will export gas from the lower 48 to Mexico.

These companies include Sempra, TransWestern, Kinder Morgan, just to name a few.

But what we saw out of our work is that we expect exports to Mexico to increase and to reach about 3.5 Bcf a day by 2025. Then we expect to see some sort of drop off somewhere around that time, maybe 2023 or so. There's like a significant reform going on in Mexico right now. We expect that to take hold and then we expect pipeline exports to drop off just a little bit. But we expect significant exports to Mexico over the next 10, 15 years.

The other avenue for exports, of course, is LNG exports. There are at least 14 proposals on the table right now and they are for facilities to be built in the U.S. Gulf Coast, on the East Coast, and the Pacific Northwest.

Four of these proposals have already received approval. WE have Sabine Pass Liquefaction. That's in Louisiana and that is currently under construction.

We have Cove Point LNG in Maryland. We have

Cameron Liquefaction in Louisiana, and we have Freeport Liquefaction in Texas.

So, these things are expected to be built. I don't know what's going to happen with the rest, but they may be built also. We have to wait and see what the market tells us.

Now, to California. This is a 2025 snapshot for California. Of course we have our demand. We have a demand of about 6.4 Bcf a day. This is in 2025, this is our snapshot.

Now, how is that demand going to be satisfied? Well, it will be satisfied by about 2.7 Bcf coming in from the north, at Malin. We'll have about 1.25 Bcf coming from the Rocky Mountains, and about 2.23 Bcf coming across from the southwest. And, of course, we're going to have a little bit of local production.

Now, the thing to notice is how small our local production is. About 10 or 15 years ago, maybe 10 years ago, I should say, we were producing about 15 percent of our demand. Today, we are producing about 10 percent.

We are projecting that unless something changes, unless something changes we are only going to be doing about 3 or 4 percent by 2025.

This is a question for the panelists, what could we do about that or should we do anything about it?

We'll speak over that here, in a little bit.

So, what's going to happen to prices. This particular graphic shows us the prices at Topock. You can see this is our high price case, that was our low price case, and this was our reference case. And you can see prices moving up, moving up until it will probably reach about a $5.00 level, also, in 2025.

So, the high-price case behaves as expected, the low-price case behaves as expected. Those two lines formed a zone of uncertainty. And we expect that prices will deviate between those two as we go into the future. And this is something that we'll be looking at a little more as we go through this present cycle in terms of prices and their behavior.

Now, in terms of production, I put up these two schematics to show the contract. In the lower 48 we are seeing great expansion of natural gas production. Of course, you know the reason for that, shale. The development of shale have truly expanded our supply portfolio.

We expect, around 2025, we should be producing something like 75 Bcf per day. But if you look at what's happened in California, in all three of our cases that we did, California production is declining and declining pretty significantly.

Like I told you a little while ago, we expect that by 2025 California will only produce about 3 or 4 percent of its demand. This is something that we would like to talk to the panelists about, what should be done about it, or if anything at all should be done?

That takes me to the end of my presentation. We'll now get into the panel discussion.

So, could I now ask our panelists, Sharim, and George Pickering, please join us. Gordon Pickering. Gordon, I just renamed you and I apologize. I hope you don't hold it against me.

Like I said, I used to have black hair when I started here at the Commission, and it's gray hair.

So, we'll now go into our panel discussion. Thank you very much for listening.

There we go, all right. Now, we will suppose -- oh, not so loud. Okay. All right.

We were supposed to have four panelists today, on this panel. Unfortunately, one of our panelists is stuck in an airport someplace, and another one decided not to join us here, today.

But we have two distinguished gentlemen here who will help us with some of the issues that we are about to discuss.

So, the first of which is Sharim Chaudhury. Am

I pronouncing that?

MR. CHAUDHURY: Yes, very good, close enough.

MR. BRATHWAITE: Thank you. I don't want to butcher your name.

MR. CHAUDHURY: No, no, you did great.

MR. BRATHWAITE: Anyway, Sharim is the Manager of Gas Demand Forecasting and Redesign within the Regulatory Affairs Department of SoCal. His department supports the gas regulatory activities of both SoCal and SDG&E.

Prior to joining SoCal in April 2013, he worked at Southern California Edison for 13 years, holding several positions, from Senior Analyst, to Manager of Price Forecasting, to Manager of Long-Term Demand Forecasting.

Sharim holds a PhD in economics from the University of California, in San Diego.

Sharim, welcome.

MR. CHAUDHURY: Thank you.

MR. BRATHWAITE: Our other panelist is Gordon Pickering, who I renamed George a little while ago.

(Laughter)

MR. BRATHWAITE: Gordon is the Director of the Energy Practice at Navigant Consulting. Over the last 30 years plus, Gordon has acquired vast experience in

North American energy consulting, in oil and gas exploration and production, in power industry in both the United States and Canada.

He currently leads Navigant's North American Natural Gas and Energy Practice. That practice has been a market leader in identifying gas shale development through the technology breakthroughs that we are now witnessing in the oil and gas industry.

Gordon has a strong background in energy pricing, particularly in natural gas and LNG, and in the area of price forecasting and risk management.

He's a sought after speaker, having spoken widely at industry conferences and other events across the United States, Canada and Europe.

Welcome, Gordon.

So, what are we going to be doing here? We'll be talking a little bit about production, supply, and demand to some extent, and any associated issues.

These gentlemen here are industry experts and we'll be -- hopefully, they'll be able to help us to decipher some of these issues.

As I go through these questions, I invite anybody, whether in the audience or on the WebEx, to please chime in with questions, or comments, or any opinions that you would like to offer as we go through the questions.

If you decide to speak, though, please identify your name and your affiliation, so that everyone can know where -- who you are and where you are coming from.

So, having said that, why don't we just get into the questions.

So, the first question that we have on the table is what technological advances have there been in conventional natural gas production that could benefit California's natural gas production?

As you saw from my presentation, California production is declining and declining pretty significantly. And is there something we can do to arrest that or is there anything that we should do to arrest that decline?

So, Gordon, why don't I open it up to you and could you maybe give us some perspective on that particular issue?

MR. PICKERING: Thank you, Leon. Thank you very much. I think it's been four years since I was here last. Here we go. I think it was four years since I was here last and we were talking at that time, and I believe, if I'm not mistaken, that Terry Engelder from Penn State University, also joined us on the phone.

MR. BRATHWAITE: Yes.

MR. PICKERING: And there were others that participated. And what the topic was, was somewhat similar. It was about production and supply in the country at that time. And the day was rather different than what it is today. I appreciated your comments here, Leon, and I think they're very astute in terms of the market that we have today.

And I think what we need, to first of all frame this discussion, is how far we've come in a very short time. So, what you've outlined here and if we were to look back at the notes from four or five years ago, or however long that was, not very long ago, I think we were talking about, but we were also realizing that we had a very different market.

If we go back to 2008, as a matter of fact in this country the situation was that we were in a supply deficit and we were running out of gas supply. The country was reliant upon LNG import facilities to make sure there was enough supply to service the needs of the industry going forward.

As Leon and most people now recognize, this situation is quite different, now. And also, which Leon mentioned, that you might have caught, is that we are in a situation, now, of abundance, and as a matter of fact in a surplus situation. An imbalance market characterized by surplus supply and not necessarily the healthiest market that you want, either.

So, we have two ends of the spectrum here. A situation that was at least of perceived shortage a few years ago, challenges for supply/demand balance, which most economists will tell you is the ideal, to a situation today where we have surplus of supply, and a situation where we're trying to manage that imbalance again, yet in the other way.

In terms of the particular question here, what we are -- what Leon is focused on, I think is conventional, and conventional natural gas production and the techniques.

I think that what -- where we first have to appreciate that conventional gas production, there still is an awful lot of conventional gas production in the country.

All of the press and all of the pizzazz in the industry, if you like, is around gas shale for good reason. But there is still a substantial amount of gas supply that is produced in the conventional area. And this is really where I think maybe the question has been addressed.

And in the conventional, like in the unconventional gas shale, or tight gas, or coal bed methane areas, the industry will tell you, the producing industry will tell you that they learn most by actually working, by actually doing things, by actually drilling.

And through the short period of time here, in the evolution of the gas shale development, I think what you've seen is a remarkable set of circumstances that when the industry get busy they learn a lot. They learn different techniques. Efficiencies are developed. Technology increases. And, as a result, costs go down.

And the same kind of thing likely is occurring, I submit, in the conventional gas area. Out of necessity, to some degree, that the conventional gas industry, like the unconventional gas industry, which is setting the trend these days, is needing to be competitive, one with the other.

So, if you're a conventional gas producer, you need to be able to look at the economics of the unconventional gas folks and what they are doing to produce gas to be able to meet the market.

So, that situation applies in California here, but also I think we'll talk a little bit later about unconventional opportunities here in California that are certainly there in terms of the resource.

MR. BRATHWAITE: Oh, absolutely.

Sharim, could you -- do you want to add

something on that?

MR. CHAUDHURY: Yes. I think, you know, some of the advances, you know, like the technological advances is seismic surveys and the horizontal drilling really also helped in conventional gas production in California, in the sense that, Leon, you showed your chart that the California production is going down.

So, all this enhancement, if anything, it helped to slow down the decline. Okay, so that's all I would like to add.

MR. BRATHWAITE: Sure, okay. Does anybody in the audience have a question or have a comment on this?

Okay, anybody online?

Okay, hearing none --

MR. CHAUDHURY: Yeah, we are kind of lonely up here, we'd like to have more people here.

MR. BRATHWAITE: Really, absolutely, you know. People just walked away from us.

Okay, so let's move on, then, to question number two. From your perspective, what will be or what do you think will be the future of natural gas production here in California, given some of the constraints we have here on production. In particular, I would probably have to mention, maybe, some of our environmental constraints.

Now, today we are not talking anything about emissions or anything like that. That will be in a future workshop. Right, Silas?

But the other environmental constraints, what do you think the future is going to look like?

Sharim, why don't you lead us off in that regard?

MR. CHAUDHURY: Yeah, you know, if you look at the 2014 California Gas Report, where we basically, like you, look at the gas supply meeting California gas demand, what proportion is coming from California production versus out-of-state.

And in this report, both for PG&E and us, we are really seeing virtually flat. We were showing some decline, but we are showing virtually flat, you know, production. So, we really don't see production increasing. If anything, it probably will go down for the reason that you mentioned earlier in your presentation.

MR. BRATHWAITE: Sure, okay.

MR. CHAUDHURY: So, we really don't see any change. It will be pretty insignificant. But given that the demand is totally going down in California, so that if you look at it proportionately, maybe the California production will be slightly higher by 2020 to

2035, compared to now.

MR. BRATHWAITE: Uh-huh.

MR. CHAUDHURY: But in terms of absolutely level of production, it’s going to be virtually flat or slightly declining.

MR. BRATHWAITE: I see. I see. Gordon, what do you want to add to that?

MR. PICKERING: Yeah, I mean, I wouldn’t necessarily disagree with a flat to slightly decreasing production profile here from California.

But a couple of things. I would not suggest it’s necessarily a result of demand. I think it’s apt to be more supply driven. There’s a lot of competitive gas supply in adjoining states and adjoining built-in pathways behind existing transportation corridors. A lot of work that is going on in areas, including British Columbia I will add, to the north, that seems to be under-represented here so far in the some of the dialogue that we hear across the United States.

But that, certainly, there are a lot of things that are developing there.

And in terms of the supply and what is apt to happen, I would like to be clear that the answer to this is not probably resource-driven, either.

So, the reason why maybe a flat profile is apt to be in existence in the future is not because of the resources in here. We do know, for sure, at least there's a good likelihood that this State, and we haven't talked about this, but holds, perhaps, the largest oil shale resource maybe known in the world today.

With that oil shale, and recognize that some of the numbers in terms of the resource base have been adjusted by the Federal Government here, over the last year or so, nevertheless, I don't think that the Federal Government has indicated that they are confident enough to say that this is -- means that the resource has disappeared all of the sudden.

It's mainly because there hasn't been enough work done to be able to substantiate or really prove up the oil shale.

And with that oil shale development, the reason why I mention that, is that there's apt to be associated gas.

MR. BRATHWAITE: Oh, yes.

MR. PICKERING: So, gas that is produced. So, if the very valuable, and even under an environment of decreasing oil prices currently, these have gone down pretty quickly, but they can also go up, so we need to remember that. In this environment there is an opportunity for substantial gas to be produced, yet, in California.

But in my own view, it's that it is more a matter of what does California want to do? I will say that my feeling, and what I see around the country in terms of the industry, the industry is flat out -- the industry has a lot of opportunities these days in terms of developing other areas.

The Permian Basin, we haven't really talked about, yet, is just going flat out. Eagle Ford, of course the Bakken, and then the big shale plays, in particular the Marcellus and the Utica, demanding a lot of the efforts of the industry.

And so, California becomes a bit of an afterthought. And the history of California is at least unclear in terms of the signals sometimes that it gives the producing industry. And to the extent that California would, I believe, clearly indicate a path forward, and the State must also congratulate itself in some ways in making great strides, in a short period of time, forward in terms of its regulatory structure for the development of shale gas and other forms of gas in the State.

So, there's still things that have been done, but things to do. That will, you know, indicate maybe how much production potential is still left.

If things shape out, if the people of California decide that this is something that they would like to pursue, I think the resource is there.

If not, there's still enough gas from other places in the country to meet the needs of California going forward.

MR. BRATHWAITE: So, Gordon, are you -- if I'm hearing you correctly, are you saying there's -- that the issue will play out depending on the economics of pipeline gas, gas being piped into California versus gas being developed locally here, within the State? Am I hearing that out of your assessment?

MR. PICKERING: Yeah, everything is going to be, I think, competitive is what I'm saying. So, anything that's developed here will need to be competitive with gas produced from other places and transported into the marketplace. That's just the way it works.

And I think you've seen some examples, recently, with the Western Canada resource, the Western Canadian Sedimentary Basin running into competitive issues in delivering gas into the U.S. northeast markets because of the transportation cost versus, now, a new alternative that markets have in the U.S. Northeast with the Marcellus and the Utica.

MR. BRATHWAITE: Yeah.

MR. PICKERING: So, California would be no different in that indigenous supply which, if it's closer to market perhaps has a transportation advantage versus other gas coming from other places, like the Rockies or from Western Canada. So, everything being equal, which they never are, but getting through some technical, technological advancements and such has an opportunity to be competitive and maybe more so.

MR. BRATHWAITE: There you go.

Sharim, anything else you want to add on this?

MR. CHAUDHURY: No. I think, you know, given the current prices and we're not even, now, going to the regulatory environment, you mention it will be another area, you know, environmental issues. I don't foresee, you know, the Monterey shale being developed, you know, in the next 15, 20 years. And that's why we are basically sticking with the CGR forecast of really conventional gas, at most at current level.

MR. BRATHWAITE: So, are you saying that you think the regulatory environment or the environmental constraints will probably prohibit the development?

MR. CHAUDHURY: You know, it will be one factor, along with the abundance of gas, you know, in the rest of the United States, along with the price of gas --

MR. BRATHWAITE: Right.

MR. CHAUDHURY: -- these all will play a role in sort of having, you know, Monterey shale to be developed.

MR. BRATHWAITE: I see, okay.

MR. PICKERING: I just would add here just a thing, and I don't know where things, frankly, will end up with the Monterey. But I would just suggest that we don't, certainly, write this off, and recognize how fast things can turn in a very short period of time.

We are also talking about oil and with its value and its import. So, in this country it has a different connotation, different value system, apparently, to natural gas.

And should the forces that be, the public in California certainly, perhaps broader than that, decide there is some economic reason to develop the Monterey shale, oil shale, but with it considerable gas production, then we could have a quick reversal of fortunate that just will cast, you know, one's view back to 2008.

Not very long ago, six years ago, when people and there were many, most of the industry was saying this is not possible. Navigant, you've got things wrong. You're on the good stuff, you know.

So, I just, you know, don't know what's going to happen. Partly, and I think to some degree, it's largely a policy decision and, secondarily, it's a technological decision.

MR. BRATHWAITE: Okay.

MR. CHAUDHURY: I'd like to add that I agree that there's a tremendous amount of uncertainty out there, so I'm not saying that it's not going to be developed, period.

MR. BRATHWAITE: Right.

MR. CHAUDHURY: But, you know, given the situation now, the information I have, you know, it seems like compared to, Leon, your reference case, that if I'm to give a point estimate forecast, I would say it won't be there.

MR. BRATHWAITE: Okay. But I was just wondering something, though. We were talking about the possible development of the Monterey shale. And we know that in other parts of the country the hydraulic fracturing and horizontal drilling have been used quite effectively to develop natural gas resources.

Do you think those techniques can be combined and used here in California, given the geology within the State of California?

MR. PICKERING: I, myself, am a tremendous believer in technology. And that recognizes that there is a different geology here in California, apparently with the Monterey shale. But I'm not persuaded by that, that will be the determining factor as to whether the Monterey shale is developed at all. I think far from it.

I think the industry, at the appropriate time, and also layering in economic production, given what we are talking about is oil. And oil, the way its value, most of us know, is 45 times more valuable in some sense, or more costly in others compared to natural gas on an MMBTU basis.

So, the oil, I would say, and the public dialogue around the Monterey shale, because of what it is, deserves some different considerations, and different policy considerations than natural gas.

MR. BRATHWAITE: Okay.

MR. CHAUDHURY: As you know, Leon, that the currently brand crude is trading at around $77, $76, $78. So, there's some questions about, at that level of oil price and it's expected to may even go down for the rest of the year and next year. And given that, there's some questions about all this shale play. You know, what shale plays, where, you know, gas is the associate production, along with the oil, which really brings the bucks home.

The question is, is that how -- whether will it go down where there's some of these production from the Monterey shale will be affected. So, there's a tremendous uncertainty out there, as you know.

MR. BRATHWAITE: Yes, indeed. Indeed.

Anybody from the audience want to chime in, at all?

How about anybody online? Could you read the comment?

(Comment from WebEx): "I agree with Gordon when it comes to the Monterey, it's about oil. And the gas, just as it is in the Bakken, is a foster child, according to major input holders. And in the Monterey, the economics are not yet ripe for development."

MR. BRATHWAITE: Yes, please come to the mic, your name and your affiliation, please.

MR. RUBEN: My name is Greg Ruben, with Kinder Morgan. A quick question for you guys, when we look at that relationship, the crude oil prices dropping to the $70 range, and I've seen some of the studies and reports that are suggesting that some of the producers would still be looking at substantial returns if they kept their rig count up.

So, you know, even at $70, they're projecting, some of these major producers, large independents are still looking at 20 plus returns on their drilling activity.

So, do you still feel comfortable that we'd see a decrease in the rig count because of that temporary, I guess, or even if it is long-term drop in the crude prices, or would you consider that those producers would continue to drill at the reasonable levels that they're drilling at today?

MR. CHAUDHURY: You know, producers first pick up the low-hanging fruit. So, current one, they're using, probably a lot of them are still profitable at $70, you know, oil price.

But I'm also thinking that if they're going to more and more expensive shale plays, whether it will be economic to do that.

MR. PICKERING: You see how quick, we're talking about gas, we're now talking about oil, and we're also talking about the world market. So, we have everything -- in a year or so that will be globalized in this energy discussion, with gas connected from North America, for the first time, with the rest of the world as the oil market has been forever.

So, this begs for more and more interesting discussions all the time. The price of oil and the price of oil in North America, I think is the question here, and the economics at $30 - - $70 a barrel, is that economic? I think it has every reason to be economic for a lot of producers. I think there are certain oil production sources, some of them very large, like the Albert Oil Sands, that may have some different economics in their makeup, and because of the size of the resource. They're perhaps the fourth largest deposit of oil in the world. May have some different and this question becomes more -- I think at $70, they're still fine. But at some point, before the rest of the industry, perhaps in North America, becomes constrained by economics, the Oil Sands may be the first.

The economics of developing the Monterey oil shale, in California, no one knows what exactly it will take because there hasn't been enough work done, as far as I can tell.

But one thing I will say, I'll relay a little story and sort of an anecdote from what I'm hearing out of foreign markets, and which apparently is coming from the Middle East, and an arrangement that came up a week or two ago in terms of the OPEC reducing the oil price, or reducing production to maintain the -- retain prices the way they were.

They decided, OPEC decided not to curtail production and let things go. They are looking, no doubt, at the U.S. oil market and increased production from North America, and felt like there is more downside and more economics in the North America oil production. So that if they decreased production, all that would happen would be that the U.S. producers may up their production levels to take advantage of the supply declines.

How this tracks into the gas world, too, is very interesting in that there's been some press here, recently, that as a result of declining oil prices and, therefore, possible production declines, which I don't agree with, Navigant doesn't agree with, on the oil space that lesser amounts of gas will be produced in the country and gas prices will go up, as well.

This argument, as we can appreciate, centers around the associated gas or liquids production that is -- and gas being produced in association with wet gas, especially in the Eagle Ford and in the Bakken areas. And if oil prices go down, will gas production go down and prices, as a result, go up.

I would only offer this, that there's only, and according to our estimates, only about 14 percent of the market in the United States that have produced through associated gas.

So, my view would be that if there was a decline in oil production and, therefore, tracking through on the associated gas part of the oil metric, that it would have a very small part on the market. And those places, such as in the Monterey, that are behind pipe, gas has already been drilled that is waiting to be tied in other places, as well, would apt to jump right in to be able to maintain gas production.

A long, convoluted story about talking about the interrelationship between oil and gas, and what would happen with gas as a result of oil price decreasing.

MR. BRATHWAITE: Oh. Anybody else?

Okay, so let's move on to question number three. I'm going to switch gears just a little bit, but it's still related to our discussion here.

So, over the past several years the U.S. have undergone a well-publicized shale gas boom that has been facilitated by technological advances in seismic surveys, combined with hydraulic drilling and -- the horizontal drilling and hydraulic fracturing.

The resulting flood of new supplies on the United States natural gas market has caused a number of companies to file for permits to build LNG export, underline export, terminals with the intention of exporting gas to foreign countries.

This was something that was in my slide a little while ago.

Taking into account the economic and permitting hurdles related to building LNG export terminals, what is a realistic outlook for the impact of LNG exports on the U.S. natural gas market?

Under what circumstances would the U.S. LNG export market result in U.S. supply shortages or price increases?

What is the jurisdictional issues that arise in permitting LNG export terminals?

I mean, I would also like this to be in context with the fact that just a few years ago we were talking about LNG regasifications. We had a bunch of, I think there were 12 proposals to build facilities here, in California.

So, given that history, I would like you guys to speak to this issue as best you can. So, let me start with Sharim, and Gordon, I'll come to you next.

MR. PICKERING: Yeah.

MR. CHAUDHURY: Okay. I was looking at the Energy Information Administration, the EIA 2014, you know, annual energy outlook. And they look at multiple scenarios. Okay, they have a reference case. They have a very optimistic oil and gas recovery scenario. They have a pessimistic scenario. And they look at also high economic growth. And they look at also like accelerated coal and nuclear replacement with gas-fired generation.

And after they did that study, and just to give you an example that under this study, in the reference case, you know, EIA said in 2015 there would be a 0.3 Bcf LNG export. Okay.

Now, after they did this study, apparently Department of Energy went back to them, and as they were coming out with the report for prospective, you know, LNG exporters that whether export would be beneficial in the public interest, DOE asked them to basically say what are the price impacts, for example, of several scenarios.

One is export of 12 Bcf LNG export starting in 2015, with incremental of 2 Bcf every year. That's one scenario.

The second scenario was 16 Bcf export, total again with a 2 Bcf incremental every year.

And the third one was 20 Bcf, okay.

And just to give you that -- just to let you know that EIA had thought some of the expansion in the early years that DOU was looking for, it was very, very optimistic, okay. In fact, in some cases it's been unrealistic because it cannot ramp up, you know, the export so rapidly given we don't have the infrastructure here, yet.

Given that they recognized that the DOE request was sort of the outer limits, okay, that even though it's not going to be that much, say what is the sort of extreme price impact, okay, capturing that.

So, in that scenario, what EIA did is they looked at the initial, say for example, reference case, and they superimposed the additional LNG export to get to the -- for example, one case is 12 Bcf by 2020, starting in 2015, incremental of 2 Bcf.

Then another scenario is, you know, 16 Bcf, another is 20 Bcf.

And what they found is that if they took the reference case, then the price increase would be like four percent, okay. If it was 12 Bcf export, LNG export, versus 11 percent price increase if it was 20 Bcf export.

MR. BRATHWAITE: Oh, okay.

MR. CHAUDHURY: So, their conclusion was that the increasing supply can be met, and the export, together with domestic increase in industrial demand, and also for the EG growth, okay, the gas for EG demand growth can be generally met with the increasing in the supply of natural gas from -- primarily from the shale plays.

So, they were basically saying that, you know, there will be some price increase but counter, you know, on the opposite side the economy is going to improve from that. You know, GDP would be higher. So, EIA didn't seem like too concerned about price increases.

MR. BRATHWAITE: Yeah, so it might have some price increase, but supply shortages might not essentially occur, is what it essentially is.

MR. CHAUDHURY: Right, right.

MR. BRATHWAITE: I see.

MR. CHAUDHURY: And important thing is that an LNG export is not really exogenous. Even though the way DOE wanted them to model it is exogenous. You know, LNG export is exogenous. It's a function of how much production is there, you know, what the price is, what the LNG price is for example, what the oil price is.

MR. BRATHWAITE: Oh, okay.

So, Gordon, what do you have to add on that one?

MR. PICKERING: A fair amount. First of all, going back to the EIA's original shot at assessing what is the impact of LNG exports on the country going to be.

I think it's not going too far to say that that report was taken apart by the industry and by, possibly, their own work, subsequently.

And one of the main aspects of the criticism in that report, certainly some of Navigant's criticism on the report was that all the volumes that they developed some scenario analysis around was in the Gulf.

I think that what you're seeing is a recognition of an administration that has certain biases built into some of its own analysis, and because of what they knew at the time they felt like these projects in the Gulf would be, perhaps, the only projects to go forward.

It makes a tremendous difference. And you can see in the eight LNG export applications that Navigant supported to the DOE, of which we have yet to not get approval of those that have been heard by the DOE, including the first project, so the impasse of Chenieres.

Is that our finding, by doing a modeling of the individual project, itself, with some scenarios in the event that other LNG was to come on from other projects, we allowed for that, what would the impact on pricing be.

And our finding was that, really, looking at a monthly basis out to 2035 and, lately, we're projecting to 2045 and 2050, we're finding that the impact is very little, both in the local market and also in the national market, as referenced at Henry Hub.

The thinking behind that, when one takes a look at that, is that there has been a change in the resource base. So, if we always go back to the fundamentals of the industry, I think we can save ourselves a lot of anguish.

But as the industry has evolved from a southwest-centric kind of a supply basin, toward the northeast and now, certainly, into the midcontinent area in the Bakken, and British Columbia and Alberta expansions there. Despite what people are seeing in Alberta, there's probably still potential there to turn around their decreases.

But as this shale resource, in particular, has become and recognized as being more regional across the country, then you have more opportunity for regional projects to be built based on regional supply, supported by regional supply, with a much different impact on the resource base as measured at Henry Hub, or any national reference point.

So, our findings were that without exception, and I think interestingly for us here in the west, is that our clients at Oregon LNG, and at Jordan Cove, the findings were actually, compared to the other projects on the East Coast, and in the Gulf, the end price increases were actually less.

So, you know, that's what our findings were.

MR. BRATHWAITE: Good. Very good, very good. Anything --

MR. CHAUDHURY: Leon, I'd like to --

MR. BRATHWAITE: Oh, I'm sorry, sure. I'm sorry, I apologize.

MR. CHAUDHURY: I'd like to add that apparently, right now, that there are about 40 Bcf worth of projects, export projects out there, and we know that all of them will be built, okay.

MR. BRATHWAITE: Right, right.

MR. CHAUDHURY: And the question is how much. And with the midterm election, you know, with the Senate moving to Republican Party, and I believe that there's some talk about introducing some bill in Congress where the Department of Energy needs to determine whether a project is the public interest. I believe the window -- right now there's no time limit on that. You know, right? DOE -- is it a DOE could take as long as they want?

MR. BRATHWAITE: Yes.

MR. CHAUDHURY: And I think they are putting it a time limit like 45 days.

MR. BRATHWAITE: Yes.

MR. CHAUDHURY: So, it may have some impact.

MR. BRATHWAITE: Sure, absolutely. Absolutely.

MR. PICKERING: And just if I can just say one thing here, that we lest -- we shouldn't forget, and the question here is, as I look at the words, under what circumstances would the U.S. LNG export market result in U.S. supply shortages and price increases?

And I think it's a bit of a loaded question, but it's an important question that I want to make clear, we've made clear at the every outset of our exploration with this gas shale business in this country.

Without fracking, and without horizontal drilling, we would go back most definitely to a situation we had before 2008.

So, if you want to talk about, and the loaded question aspect of this, and it comes up in jurisdictions around the country, and in talking to people, is that there is not everyone that believes that this technology breakthrough is the best thing for the country, or for the specific region.

So, if there's one thing that maybe is understated here is to recognize, certainly not suggesting that this new technology can't be applied in a very safe, practical, best practice and complementary way for the country, but would just make the point, so that everyone's clear that if you do away with this technology breakthrough, you would go back to shortages that were perceived, at least before 2008.

MR. BRATHWAITE: Fair enough. Fair enough.

Anything from the audience or online? We have something online? Could you read the question, please?

(Question from WebEx): So, LNG exports will put a floor on U.S. gas prices equal to Japanese crude oil prices, less ocean freight, terminal and liquefaction costs, and transport costs to the field from the terminal. Again, over the long haul, it's all about crude prices."

MR. BRATHWAITE: Okay, that was a question or a comment?

UNIDENTIFIED SPEAKER: It's phrased as a comment.

MR. BRATHWAITE: Okay, all right.

MR. PICKERING: I want to talk to that. I mean, I don't agree with the premise there that, necessarily, going forward that LNG, global LNG prices, which some of which are tied to oil index pricing is going to be the way of the world and the way of the market of LNG going forward.

I think you only need to recognize and just wait, just wait until North America starts exporting natural gas at the end of next year to the world market. You're already seeing and have seen, prior to one bit of LNG being exported, the effects of, and certain things that are changing in the global market with respect to LNG pricing.

We also need to, in my view, need to keep in mind that if we are to think that we're the only ones in this continent that has access to gas shale, we're mistaken. Gas shale exists in a wide -- in wide proportions and large volumes around the world.

And as gas shale gets developed in other jurisdictions, and considering that it has different drivers than what development in this country has, which will have its own applications on the speed of development and the extent of it, we may have an entirely different global market.

So, to say that there is going to be a floor put to the market here, in North America, based on oil index pricing, don't agree with it.

MR. BRATHWAITE: Okay, fair enough.

You know, after we lost two of our panelists, I thought we would not have -- we would certainly be done with this thing in short speed but, obviously, that's not the case.

So, I will ask the rest of the questions, that if you could be as brief as possible, if we are to get through the questions and stuff.

But let's try question number four. What would need to be done from gas infrastructure perspective to switch the Costa Azul LNG facility from an import facility to an export facility?

As you gentlemen know, that Costa Azul was built when we thought gas, LNG regasification was going to be the thing that was needed here in the United States, in the lower 48. But now, we are in a different environment and we are now talking about export.

So, Gordon, what do you think about that question?

MR. PICKERING: All I'll say, and I will keep it brief, is that Costa Azul, as it's currently configured, is facing a market like every other import facility in this country and has no commercial viability as it exists. It will be up to the owners of Costa Azul to determine whether and when they decide to reverse that piece of equipment into an export facility. That decision will be made by the owners.

Suffice it to say that the costs of liquefaction are many multiples of the regasification terminal, so it will be expensive. Looking at, and having been to the site of Costa Azul, there may be ability to be able to do that, but the costs of doing that will be not insignificant, like other export facilities being proposed around the country.

MR. BRATHWAITE: Oh, great.

Anything, Sharim?

MR. CHAUDHURY: Actually, I really don't have any exporting knowledge to comment on this.

MR. BRATHWAITE: That's fine. That's fine, okay.

Anything in the audience or anything online? No, okay. Thank you very much.

So, let's go to question number five. California's natural gas utilities have made significant investment in gas storage facilities to provide additional supply for system reliability.

Independent storage facilities provide additional natural gas supplies to the California system.

Over the next ten years, how much additional natural gas storage is likely to be necessary to ensure system reliability in this evolving gas market? Who should develop this storage?

And given the fact that we are moving into an environment where we are talking about 33 percent renewables by 2020, I think this issue about storage is vitally important.

So, Sharim, let me start with you and see what you can add about this particular issue.

MR. CHAUDHURY: Okay. Well, the storage, you know, SoCalGas feels like we have, you know, in terms of the inventory, we have adequate inventory to meet our need.

A few years ago we expanded our inventory in Honor Rancho, one of our storage facilities, by about 7 Bcf additions.

Now, on the injection side we talked about and, Silas, you also had a presentation about the Aliso Canyon turbine replacement project. So, we are increasing the capacity that that has, the ability to increase the capacity by 145 MMCLD, million cubic feet per day.

And on the withdrawal side, we don't see any need, currently, okay.

Now, on the PG&E side, I think they have talked about in the CGA report, and also today that there's plenty of storage capacity, both by PG&E and also, you know, other parties.

Now, in Southern California we really don't have any other party currently, other than SoCalGas. And Silas, in your presentation you had the ten section as a possibility, you know, they are considering. And I believe that they are decided against developing that.

MR. BAUER: That particular graphic was from a 2013 report.

MR. CHAUDHURY: Okay.

MR. BAUER: So, I should have noted that it could be outdated at this point.

MR. CHAUDHURY: Okay, yeah, I think.

MR. BAUER: But on short notice I threw it into the presentation, knowing that I had not checked on that TRICOR 10 Project in a little while, and knowing that we hadn't heard much about it recently.

MR. CHAUDHURY: Yes.

MR. BAUER: So, I couldn't say a definitive no, yet, but --

MR. CHAUDHURY: Okay. Now, SoCalGas, you know, we're not against independent storage facility in our -- in Southern California. It's just that the geography doesn't support it. You know, there are not much, you know, used up oil field, or a gas field that can be used as a storage facility.

The incentive, currently, is that if you look at the difference between winter and summer gas price difference, okay, it has pretty much collapsed, okay.

So, to develop new, independent storage

facility, we feel the economics is not quite there, okay. Because, typically, you fill this storage in summertime when price is to be lower and use it up in wintertime. And also, the price volatility is not there as much.

MR. BAUER: I see.

MR. CHAUDHURY: And our peak demand forecast is virtually flat, okay, so we don't see any need for any additional storage.

MR. BRATHWAITE: Okay, very good.

Gordon, anything?

MR. PICKERING: Just a couple of things. And I really like that we are talking about gas related to the renewable industry. That's the right way to frame this as two commodities, two energy sources that need to work together. Enough said on that.

But the situation, also going back to some fundamentals, changes to the market as a result of gas shale, and what has been referred to, and keep in mind when we're talking about storage, is the volatility and the potential, and we've seen some signs of it, despite what happened last winter, that with gas shale, and what we have described as a manufacturing process of gas shale development, has the potential to impact volatility in the gas market going forward.

The volatility of pricing in the gas market has been the bug bear of additional market for natural gas long before now.

But with this resource as the sliver, of the total gas production becomes the majority by 2020, we now begin to have 58 percent of the market producing supply side of the U.S. market being -- coming from gas shale.

Then, you start to have more of an impact, as we go along, of gas shale and the type of resource, fundamentally, that that is, that lends itself to less price volatility in the market going forward.

That, again, is a roundabout way of then starting to address this storage situation which, as a result of a regional disperse nature of the gas shale resource around the continent, plays into the economics and the commercial basis between, certainly Henry Hub, and the demand areas, and in California.

Which suggests that, from a commercial basis, hard to put the economics together. And I don't think this is going to change. It's apt to be more apparent going forward.

Leaving the situation that if there is more storage to be built in California, it probably needs to come from the demand side, whether that's the utilities, from the State, itself, who knows. But my guess is that if additional storage is to be built, it will not be done by the producing sector of the market for some time.

MR. BRATHWAITE: Okay. Any comments from the audience or online?

Okay, hearing none, we'll move on to question number six.

Sharim, I'll got you again, and then Gordon will tie up on question number seven.

The polar vortex that led to the gas supply shortage and the curtailments of electric generation facilities in February of 2014, highlighted the fact that California, despite having a great deal of redundancy built into its natural gas infrastructure, is not immune to supply constraints.

What is the outlook for the U.S., and California in particular, this coming winter in terms of gas storage availability, gas supply, and potential weather events?

Sharim.

MR. CHAUDHURY: Okay. Now, this came up in multiple sort of group discussion today, this morning and afternoon, so I'll be brief.

So, the bottom line is that the problem was not a shortage of physical gas supply. Basically, the gas moved exactly as we expected it to move. It moved to higher price markets, okay, given the incentives, okay. So, that was not a supply.

So, what caused it? And we believe the problem is with our sort of very relaxed winter balancing rule, okay. And that's why, Silas, as you presented that most of the time the effective winter balancing rule is that within a five-day period, you know, you have to bring in 50 percent of your usage, bring in supply.

So, on a particular day, when the price is very high, say for example, even in supply basin, compared to SoCal border, or in northeast, you can deliver zero amount of gas, okay.

So, I think the main problem is our very, very relaxed winter balancing rule. And we are trying to correct that through our OFO application. And we are proposing very similar to what PG&E's, you know, low OFO rule.

And it seems like PG&E has gotten through this polar vortex issue better than we did, okay, so I think our winter balancing rule tightening up is going to help.

MR. BRATHWAITE: Okay. In the interest of time, is there anybody from the audience have anything, quickly? Or online? No, okay.

Well, in the interest of time, Gordon, let's go on to question number seven.

MR. PICKERING: Okay.

MR. BRATHWAITE: And I will ask you to -- let me just read the question and then you can answer as you see.

Mexico has plans to convert many of its oil-fired electricity generation facilities to natural gas and to build many new gas-fired electricity generation plants.

Although Mexico's recent energy reforms would encourage new natural gas exploration and production in Mexico, significant increases in domestic production are not expected for years to come.

In the interim, Mexico will be importing more gas from the U.S. over a new pipeline new interconnections, or over the same interstate pipelines that supply Southern California Gas Company's Southern System.

What are the risks that these increasing natural gas exports to Mexico will cause supply shortfalls and/or price increases for Southern California?

And you remember, during my presentation, I did show you what Mexico imports are going to look like through 2025.

So, if you will, Gordon, could you address that for us, please?

MR. PICKERING: Yeah, as exports to Mexico, from the United States, increase, and our forecast would be -- would agree with the increases. I'd have to take a closer look at the numbers, but certainly think that's the case.

And cap the course by potential resource development in Mexico, especially in Nuevo Leon, south of the Eagle Ford, and that area, probably, that has great potential, itself, to produce gas in some time horizon.

But I would only go back to while the exports to Mexico are increasing, so are production, and certainly production potential, but production from the Marseilles, in particular.

And look at the production profile of the Marcellus, as additional pipeline capacity gets reconfigure out of the Marcellus, is apt to even play into a California story.

So, as the market shifts toward additional supply into Mexico, other changes will compensate within this country and within Canada to be able to more than compensate, all based on a situation here that we have in North America of natural gas supply abundance.

MR. BRATHWAITE: Good. Sharim, if you have something brief to add?

MR. CHAUDHURY: Yeah, very briefly that, you know, part of the export to Mexico would be supplied through the El Paso South Main Line, you know, through lateral either in Texas or Arizona, for example, okay.

So, the concern is that the delivery to Ehrenberg, or Blythe on the California side could be impacted.

So, can we expect -- could price -- could export to Mexico drive up the prices? Yes. Because if you look at what the major growth would be in electric generation in Mexico, and part of that electric generation would be converting from, you know, oil-fired generation to gas-fired generation.

So, potentially, they could pay a higher price than the current $4, okay.

So, clearly, that gas demand is going to compete with delivery at Ehrenberg. And given that they're switching from oil, you know, they potentially could pay a higher price, okay.

MR. BRATHWAITE: Oh.

MR. CHAUDHURY: And also, you know, it's not only the price going up, okay, that their supply may not be available because we're at the tail end of the straw, you know. Gas can leak out before it gets to Ehrenberg.

MR. BRATHWAITE: Okay. Does anybody, quickly, in the audience have anything to add?

MR. PEDERSEN: Normal Pedersen, Leon, for SDGC.

MR. BRATHWAITE: Okay.

MR. PEDERSEN: We tend to agree with Gordon Pickering. And one thing that Gordon did leave out was not only do you have the reconfiguration of pipelines bringing gas out of places like the Marcellus but I think you said earlier, the permitting is going flat out.

MR. BRATHWAITE: Yeah.

MR. PEDERSEN: And actually, at the April 16th, Gas Stakeholders Workshop, Kinder Morgan gave an excellent presentation on how -- I won't repeat here --

MR. BRATHWAITE: Yes.

MR. PEDERSEN: -- on how supply is increasing in the Permian.

Now, Sharim, you indicated that there might be a problem because gas will leak out, I think you said, off the south main line and not make it to California.

That is probably the problem that needs to be addressed by California, making sure the capacity on the south main line continues to be there. There's going to be an abundance of supply, the supply is going to be there. Make sure the capacity is there to get the gas to Ehrenberg.

And certainly, in our view, there are multiple answers to that. For one thing, you know, we've had a great experience with the memoranda in lieu of contracts. We've had a great experience with the baseload contracts.

Taking care of the Southern System for winter 2013-14, as we discussed this morning, you know, one possibility, after we go through this three-year experimental period with the baseload contracts and the MILCs, is to make them longer term.

And so, the party who's holding the baseload contract will see it in his interest to go out and take the capacity on the south main line to assure that that capacity is there to bring the gas to California.

And we might even go so far, I mean I don't know if we want to go there, but we might even go so far as to do what we did with -- what the CPUC did back in 2002. You remember there was a problem with a turn-back, capacity being turned back to El Paso and the Commission came along and ordered the utilities to procure capacity on El Paso.

That's kind of an extreme step but, you know, we could even go there, maybe with the utilities hiring asset managers to use that asset to bring gas to California.

So, there are multiple solutions to being sure that we have the capacity available to bring this abundant supply to California.

Thank you, Leon.

MR. BRATHWAITE: Thank you very much.

Anything else? Oh, you want to say something, Gordon?

MR. PICKERING: Here, here.

MR. BRATHWAITE: Okay.

MR. PICKERING: It sounds like we're in the northeast here, right.

(Laughter)

MR. BRATHWAITE: That was it?

MR. PICKERING: That's it.

MR. BRATHWAITE: Okay. Are there -- wait, gentlemen, we're not done, yet.

Are there any comments either in the audience here or anybody online? No.

Okay, hold on. Yes, certainly.

Anyway, this brings us to the end of our panel discussion. Sharim Chaudhury, Gordon Pickering, on behalf of the Energy Commission, I thank you.

I will now turn it back to Silas.

MR. BAUER: My quick note is just to say thank you very much to both of you. You did a commendable job carrying the load for what was originally supposed to be even six people on this panel. And then it was four. And then it was two. And the questions were written for the six people.

And so, you carried the load on a lot of questions that weren't necessarily designed for you, so I really appreciate that.

That brings one other quick note, and this is for everybody who's here, and also anybody listening, all of the questions for all three panels, not just this panel, but all of the panels are online, in our docket. And we encourage anybody, who would like to take a stab at answering any of the questions to go in, take a look at the questions, and then e-file your comments and your answers in our docket. That would be very helpful.

So, if there are people who are listening now, who were originally supposed to be here today, please feel free to write your answers down and send them into us. Thank you.

MR. KENNEDY: I'll just mention this workshop is being done in conjunction with the Natural Gas Working Group. In the past, we would have Natural Gas Working

Groups here at the Energy Commission, and this would give us an opportunity to talk about natural gas issues, and to have a healthy discussion about the issue then.

As you can see, we've done just that today. So, at this time, this is an opportunity to open it up to all Natural Gas Working Group members, or whomever else here, in the room, or even online right now, to open it up to free-flowing discussion.

If you have any issues that you would like to discuss, that haven't been addressed so far today, now is your opportunity to step forward and/or submit a question online for us to discuss.

MR. FERRARI: Hello, my name is Joe Ferrari. I'm a Market Development Analyst for Wartsila North America. And I just want to address one of the questions for the Natural Gas and Electricity Panel.

Question number nine said -- just in short, it said the flexible capacity of gas generation is less efficient than combined cycles. And the question is, will more frequent use of flexible capacity actually contribute to increased use of natural gas as a generation fuel for California?

And our analysis shows that the proper allocation of simple-cycle flexible capacity can actually increase system efficiency and reduce gas consumption.

Now, on the panel, earlier, gas-fired capacity was mentioned as a tool, one of many, along with storage and renewables. But I would just like to say that we see natural gas as a toolbox, there's multiple components to it.

So, we know that combined cycles are their most efficient gas generators and they're not meant for highly-cyclic operation. They're best considered as part of the fleet, but not the only part.

I see the role of flexible capacity as not being to displace combined cycle generation, but rather to work in concert with it to provide an optimal balance of reliability and cost effectiveness.

When considered appropriately, flexible capacity can increase the fleet efficiency and reduce gas consumption and CO_2 emissions by absorbing the net load fluctuations in an efficient manner and allowing combined cycles to run at a higher capacity factor, at higher loads, and with a reduction in the number of costly starts and stops.

And when I say appropriate, considered appropriately, I'm talking about two points. One is using the proper analysis techniques. So, when you're doing capacity expansion modeling moving forward to choose what types of capacity you will install, you really need to use something like chronological capacity expansion modeling.

The current methods, based on load duration curves, they don't actually give you what you need, so then you have to follow it up with dispatch analyses to sort of plug flexibility holes. And that's sort of a sub-optimal process.

And then, using a more diverse pool of flexible capacity choices, which right now are routinely viewed as consisting only of air derivative and, at times, frame gas turbines.

We think that the pool should be broadened to include other options, such as internal combustion engines, power plants which can be configured for plants up to 500 megawatts, from 10 megawatts all the way up to 500. They're modular, in unit sizes of about 10 or 20 megawatts.

To support this with our written -- with our testimony, we're going to also submit two white papers, that we co-authored with Energy Exemplar, and they've actually been shared with some of the panel members already.

These reports show that if ICEs are included in the capacity mix in California, for the years 2020 and beyond, when you're at your 33 percent, or even higher RPS, that we can actually show how this will reduce ratepayer cost by up to six percent by increasing fleet efficiency, reducing outbacks and, in turn, reducing gas and CO2 -- gas usage and CO2 emissions by up to two percent. So, thank you.

MR. KENNEDY: Thank you for your comments and we look forward to the white papers.

And just to comment on that, it's true, like necessity's the mother of invention, and seeing all these renewables put on the grid is forcing a lot of folks to go back to the drawing board. And we're seeing improvement in technologies where, you know, there doesn't have to be a sacrifice as far as flexibility, and efficiency, and for the emissions.

And, you know, responding to Cal ISO's requirements for a flexible capacity, as far as frack move (phonetic), we have been seeing a lot of requests to change their permits so that they can operate in a more flexible capacity manner. And also, new applications of new facilities to be able to ramp more quickly, in a shorter amount of time.

And you're right, using this new technology. So, thank you for your comments.

MR. FERRARI: Sure. Thank you.

MR. KENNEDY: Are there any more comments in-house, anyone that would like to step forward and ask any questions, or make any comments?

Okay. Well, I just want to remind everyone that we do have our Natural Gas Working Group meeting, we host it about twice a year. So, be sure to leave your contact information up front, your e-mail address, and I'll be sure to add you to the distribution list. And I can get the information to you as far as what kind of topics we'll be discussing and when we'll be hosting our future Natural Gas Working Group meeting.

I'll return control to Silas.

MR. BAUER: I don't have much to say. Just thank you very much for coming today. And we appreciate any and all feedback. And especially to panelists, thank you so much for participating today.

(Thereupon, the Workshop was adjourned at 3:40 p.m.)

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

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