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CALIFORNIA ENERGY COMMISSION
IEPR JOINT AGENCY WORKSHOP

In the Matter of:	)	Docket No. 18-IEPR-03
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2018 Integrated Energy Policy Report Update (2018 IEPR Update)	)	Re: Southern California Natural Gas Prices

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

FIRST FLOOR, ART ROSENFELD HEARING ROOM

SACRAMENTO, CALIFORNIA

FRIDAY, JANUARY 11, 2019

10:00 A.M.

Reported by:

Peter Petty

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COMMISSIONERS

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Michael Picker, President, California Public Utilities Commission

Karen Douglas, Commissioner, California Energy Commission

Martha Guzman Aceves, Commissioner, California Public Utilities Commission

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PANELISTS

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Marlon Santa Cruz, Natural gas Supply Group Supervisor, Los Angeles Department of Water and Power, and Southern California Generation Coalition

Mark Rothleder, Vice President of Market Quality and Renewable Generation Integration, California Independent System Operator

Carolyn Kehrein, Chief Technical and Policy Consultant, Energy Users Forum

JaWaad Malik, Vice President of Gas Acquisitions, Sempra

ALSO PRESENT

Norman Pedersen, Hanna & Morton

John Giese, Los Angeles Department of Water and Power

PUBLIC COMMENT

Issam Najm, Porter Ranch Neighborhood Council

AGENDA

P R O C E E D I N G S

10:04 A.M.

SACRAMENTO, CALIFORNIA, FRIDAY, JANUARY 11, 2019

MS. RAITT: Good morning everybody. Welcome to today's 2018 IEPR Update Joint Agency Workshop on Southern California Natural Gas Prices.

I'm Heather Raitt, the Program Manager for the IEPR. I'll go over some of our standard housekeeping items.

Restrooms are out the door in the atrium. And if there's an emergency and we need to evacuate the building, please follow the staff to Roosevelt Park which is across the street, diagonal to this building.

Please be aware that today's workshop is being broadcast through our WebEx conferencing systems and so it is being recorded. We will post an audio recording on the Energy Commission's website in about a week. And we'll have a written transcript posted in about a month.

At the end of the day, we'll have an opportunity for public comments and we're limiting those to three minutes. And so if anyone in the room wants to make a comment, please fill out a blue card and give it to me. It's at the entrance to the workshop.

For our WebEx participants, you can use the raise-your-hand feature that WebEx provides if you'd like to comment at the end of the day and we'll call on you during the public comment period. Using that same feature, the raise-your-hand feature, you can ask to lower your hand if you choose to withdraw your comment. And you can use the chat function to make contact with our WebEx coordinator.

For phone-in only participants, we will open the lines at the end of the day.

Materials for the meeting are available at the entrance to the workshop and will also be available on our website.

Comments are -- written comments are welcome and they are due by January 25th. And the notice gives you all the information about the process for submitting comments.

And our Legal Team has advised that I make the following statement.

The CPUC and the Energy Commission have called this workshop to discuss the relationship between gas supply challenges and high spot-market gas prices in Southern California, particularly at the Southern California Gas Company citygate, and high spot-market electricity prices and the consequent rate impacts on ratepayers.

We appreciate the participation of numerous stakeholders and are in an information-gathering and solution-brainstorming mode, looking for a pure exchange of ideas. The CPUC and Energy Commission are actively monitoring the situation to determine if and what solutions might be appropriate and whether such measures require the Agency’s oversight and regulation. No participants are compelled to disclose proprietary or commercially-sensitive information.

The CPUC and Energy Commission are keeping an eye on antitrust and unfair competition issues, as should all the participants in consultation with our legal representatives

So finally, I’d just like to thank our participants for being here today and request that you identify yourselves each time that you speak. That's helpful to those in the room and is particularly needed for our folks participating remotely via WebEx, and also to have an accurate transcript of the conversation.

So with that, I will turn it over to the Commissioners at the dais for opening remarks. Thank you.

CHAIR WEISENMILLER: Good morning. I'd like to welcome everyone here. Thank you for your participation. In terms of context, you know, California is very reliant on gas supplies for both home and, let's say, commercial heating, and also for power production.

We've had, you know, basically, an incident at Aliso Canyon that resulted in major methane releases. We've been struggling with that going forward, or the implications. That's been compounded now by a series of pipeline failures in Southern California.

Obviously, in a situation where you've got constraints on supply, that can result in higher prices. I think we all realize that. The question is: What's reasonable?

What we have seen at this stage is fairly strong price increases. And I think at this point, most people's attention has really gone to the Southern California Edison ERRA filing, which I believe is about $1 billion, with a B, and that's because of higher gas prices than expected.

And that comes into the question then of supply strategy. Obviously, you can do short-term or you can do long-term contracts. You can do contracts at different points, back in the basin, at the border or at the city gate, so there's pretty complicated tradeoffs there. Obviously, Edison has had a lot of experience in this area and has a lot of sophistication. But at this point, one of the major tools they've at least had historically was reliance on storage. Well, I mean, basically giving our storage limits, at this point it's really needed to deal with reliability in the core, and also some of the tradeoffs. So we have that situation.

So we really wanted to -- we pulled this meeting together today to talk about the pricing issues in Southern California to make sure there isn't -- obviously, we all know the market, at some time, can get carried away, with opportunities, to make sure there's no unreasonable prices going on here as far as we can probe it.

And as the same time that we've been marching forward, I think everyone's attention has also been drawn to look at, in Southern California, where we've had a cold spell. I mean, we've been lucky, you know, as we have gone into like last winter where things could have been pretty bad, depending upon what the weather was, and it got -- we went through relatively smoothly until the end.

And this year, we're not as lucky and we had a cold spell. With the cold spell, we have, obviously, asked for conservation measures. And there is some degree of reliance on Aliso Canyon withdrawals to really get us through that point. And this is pretty early in the winter. So I mean, going forward I'm sure people want to have some focus today not just on the supply question and supply prices, but at least we want to get on the record what happened on the demand side.

And again, you know, we're fact finding today. Obviously, there's no real decisions that will come out of this. But I think all of us felt like it would be good to get a, you know, transparent public discussion of what's going on and the consequences and what some of the options might be.

PRESIDENT PICKER: Thank you. I want to thank everybody for joining us here on this cold day here in Sacramento. It's quite gray, even though it's sunny in other parts of the state. This is the return of the Tule Fogs that we used to traditionally see at this time of year, which probably is a good sign that some of our mitigation measures are starting to kick in since the heat islands around the cities are not preventing the annual return of the dense fogs that actually help to nourish the local tree canopies. But that's the south -- that's the north part of the state. I want to talk a little bit about the challenges we're seeing in Southern California.

You know, again, Bob covered the fact the planned and unplanned pipeline maintenance outages have created bottlenecks in the Southern California Gas system. We've talked at great length about the challenges that are posed by the constraints of the operation of Aliso Canyon. We're just really starting to see the impacts of all this.

The higher prices have affected some electric generators and utilities that are under contract with the generators. It's starting to affect some of the other third-party remarketers of electricity. And we're slowly trying to grasp all the ramifications of the impact these price fluctuations will have on customers. It's starting to trickle out through the SCE ERRA proceeding into our price charging difference adjustment proceeding.

Again, the data shows there's been several price spikes since the rupture, the Line 235, in October of 2017, a year-and-a-half ago. The price spikes have been fairly significant. And they're exacerbated by the weather, well, big surprise, multi-day cold spells and heat waves.

I am always more concerned about the cold spells because they tend to affect, ultimately, the core customers more, since 60 percent of the SoCalGas system that is served by Aliso Canyon goes to those residential customers. So these price spikes have resulted in prices as high as about 40 million metric ton -- $40.00 per million metric tons per BTU, which is about ten times the city-gate prices of $4.00 per million metric tons per BTU that existed before Line 235 ruptured.

So I will say that it's starting to affect LADWP because they started to postpone some of their necessary maintenance and upgrades on their electric transmission line to reduce the overall liability risks caused by outages in the SoCalGas system. So those delays that affect the needed enhancements that LADWP has to make to upgrade its system, it may ultimately even have impacts on their ability to meet their renewable portfolio standard requirements.

So it's been over a year, again, since the rupture of Line 235. And I think that other critical lines have been out of service with no completely clear timeline for bringing those pipelines back into service.

So as Commissioner Weisenmiller pointed out, this gives us a chance to explore, not only the causes but to look at specific opportunities to mitigate the price spikes. I certainly hope we'll learn more about plans to bring the out-of-service lines back.

But I also do want to hear more about the strategies for demand reduction. We have very robust programs around demand response that have been very productive in the L.A. Basin on the electricity side, and some of that it's in response to a shortage of gas capacity. How do we deal with that on the residential side and in other uses of gas, other than electricity generation? I'm not so sure that we've having the same degree of success.

So thank you.

COMMISSIONER RANDOLPH: Thank you, everyone for participating in this workshop. I think President Picker and Chairman Weisenmiller succinctly summarized the problem. And I think the most important opportunity for today is to make sure we all have the same set of facts, that we understand what's happening out there in the market right now, so that we can think about some solutions going forward. So I look forward to our discussion.

Thanks.

COMMISSIONER DOUGLAS: Yes. Thank you, Chairman Weisenmiller, President Picker. I also appreciate the opportunity to be here today. I'm very much in listening mode and look forward to hearing what people have to say.

Thank you.

COMMISSIONER GUZMAN ACEVES: Thank you. And thank you all for being here, as well.

I do think it's important to really learn what's happening, what's happening today, what happened this past year, but also what the prospect is happening for the future, both for the immediate, next year, and for longer-term portfolio management. I'm really interested, not just in this demand-side management but also the contracting and other requirements that we may be imposing on the utilities for management of supplies, both for different reasons.

So I'm very interested in learning if there are other mitigation measures that are not being considered yet and looking at how the -- how, potentially, the management of the portfolio could be improved within the gas leak and outside of the gas leak.

I think it's really troubling to be looking at $1 billion variance in this particular set of expenditures. It's a hard thing to communicate to customers. It's not easy for us to just accept that as a normal, that this type of fluctuation should be accepted moving forward.

So I really hope to learn today and to hear what all of us can do to make this less volatile and not a reality in the future.

Thank you.

MR. RIDER: I may be unfamiliar to some of you -- is it -- am I just not close enough? There you go.

I'm here today representing Commissioner David Hochschild. I'm his Advisor, Ken Rider. We're lead on the IEPR this year and we're really happy to convene this meeting today and really thank the Chair for his leadership in the IEPR and overall on Southern California reliability.

The Warren-Alquist, which creates this Energy Commission, really leads with this fact. It says that, you know, the reliability of price of natural gas and electricity is fundamental to the operation in the state. And this is -- and price volatility is, obviously, a direct threat to that.

So I think this is really bread and butter of, you know, what this agency is here for and really happy that we can get together and talk about ways to mitigate and, you know, maintain the reliability and reasonable cost of the system.

Thank you.

MS. RAITT: Great. So again, this is Heather Raitt for folks on WebEx.

So we'll move to our first presentation, Southern California Natural Gas Prices and Electricity -- Electric Generation Costs. And it's a joint presentation with Lana Wong from the Energy Commission and Scott Simon from the CPUC.

MS. WONG: Good morning and thank you all for coming today. I'm Lana Wong with the Energy Commission.

Natural gas prices have been especially volatile at SoCal citygate this past year with significant price spikes on occasion. We've observed that these high prices are translating into high electricity prices.

Is it --

(Microphone is adjusted.)

MS. WONG: Whoops. You will hear discussion later today on the alignment of gas and electricity markets and how the timing of the markets can impact what we're observing. We've heard from stakeholders that they are being negatively impacted, which is what prompted this workshop. So we want to hear from stakeholders about what you are experiencing.

After a short presentation on prices, there will be three panel discussions on supply impacts on electric generation, impacts on core customers and non-core/non-electric generators.

So this first slide presents historical gas prices for 2017 and 2018 and SoCalGas composite temperature. What you can see is that in 2017, gas prices were fairly stable, in the $3.00 per MMBtu range until Line 235 ruptured in October 2017, and that's denoted by the black line.

So prior to the rupture, the border and citygate prices closely track together. And you can see that price volatility increases after the rupture, which clearly shows that the outages, and not Aliso Canyon, are a key factor in the price volatility.

SoCal citygate has shown several price spikes compared to SoCal Border since the rupture. And PG&E citygate prices in blue have been relatively stable during this time. And you can also see, with the yellow line is the composite temperature. The largest price spikes occurred during extreme weather, either a cold spell or a heat wave, and prices spiked as high as $39.00 per MMBtu this past summer.

So this is a map of the SoCalGas system. And it's just to remind us where the outages are. The red X is Line 235. The yellow X below it is Line 4000. The yellow X on the far right is Line 3000. The yellow denotes that they're operating at reduced pressure and capacity. And the red line denotes that that line is out. So these outages translate to about a loss of 770 million cubic feet a day of capacity, or about 20 percent of their nominal system capacity.

So for a frame of reference, SoCalGas has stated that their gas transmission system is nominally designed to receive up to 3,775 million cubic feet a day of flowing supply on a firm basis.

This slide shows SoCalGas receipt point capacity and the reductions from the outages. These numbers were used in the Aliso Canyon Winter Technical Assessment that was published last October. It shows that capacity is about a BCF lower than the nominal 3,775 million cubic feet a day capacity.

So these reductions will remain for some time, at least through this winter. And no return-to-service date has yet been identified on ENVOY, which is SoCalGas' electronic bulletin board.

What this slide doesn't capture are any operational constraints on SoCalGas' system that's impacting receipt-point capacity. So in looking at the data on ENVOY, we've seen reduced available capacity on the southern system this winter. The available capacity may be lower than what is shown here. And the southern system is, essentially, Ehrenberg and Otay Mesa receipt points on this slide.

We've also seen that that amount can be changing daily, so we'd like to understand better why this is happening and why it can change daily.

This slide shows the basis differential between citygate and SoCal border for 2016, 2017 and 2018. And so what you can see is that the differential for 2016 and '17 are fairly stable, 14 cents in an MMBtu in 2016, 32 cents an MMBtu in 2017 before the rupture. But after the rupture, you can see that the basis differential starts to widen in the latter part of 2017. And then in 2018, it continues. And you know, the average for 2018 is in the $2.00 range. So it shows that there's a larger basis differential overall in 2018.

So in trying to understand some of the reasons for that widening basis differential, we looked at data for November and December of 2017 and 2018. So for those periods, Line 235 was out during both times. But I had to remind myself that when I was looking at this data that in November and December 2017, Line 4000 was out of service, so capacity was a little bit lower in those two months in 2017 compared to these past two months in 2018.

And so this slide shows send-out. And what we found is that the send-out for these two months are similar between 2017 and 2018. The total for 2018 for these two months is just slightly lower than 2017. But it just tells us that send-out doesn't really explain what we're seeing or these differences.

I also looked at OFOs to see, okay, is that an indicator of what we're seeing? But that also doesn't help explain that when I look at

November, there were more OFOs in November 2018 compared to November 2017, but it's the reverse in December, that December shows fewer OFOs this year compared to December 2017. So that doesn't explain why we're seeing a higher differential this year compared to last year.

What this slide shows is planned maintenance activity. And what we have found is that planned maintenance events can exacerbate already constrained conditions.

So this past November there was a price spike to $19.00 in MMBtu at the citygate, and that occurred on November 16th. And so when we looked at the data, we could see that receipts at Wheeler Ridge dropped in 2016. And we found a planned maintenance event that began at Wheeler Ridge on November 16th, causing that price spike.

So it's not clear whether these planned maintenance events can be rescheduled at other times, but they certainly can exacerbate already constrained conditions.

So this slide shows receipt and whether the pipelines are full. Southern California recently experienced a cold snap earlier this month and the electric generators were asked for voluntary curtailments. There were five of them around this period. And the first notice went out December 28th. So customers are put on notice and asked for voluntary curtailments.

So the green bar shows total receipts and that they are not necessarily full. The orange bar shows core withdrawals. And the gray bar shows withdrawals for balancing. The yellow and blue lines are the receipt capacity from the earlier slide. So it just seems like receipt points should be full if the system operator is asking for voluntary curtailments. We can also see that during this time there were Aliso Canyon withdrawals. Aliso Canyon withdrawals occurred on January 2nd, a day with a notice requesting voluntary curtailments.

And so if the pipelines were full, less would be needed to be withdrawn from storage. So we want to understand better why the pipelines aren't full and what can be done to increase utilization.

So the next couple of slides are on electricity prices. And I'm going to turn it over to Simon Baker.

MR. BAKER: Good morning, Chair

Weisenmiller, Energy Commissioners, President Picker, PUC Commissioner. So this is -- the purpose of this is to just show some data that was presented in an earlier slide here, just to explain a little bit about how the electricity markets have been behaving.

By way of background, the electricity markets, they clear at the lowest cost marginal resource. And in CAISO, natural gas generators are often the marginal resource. So electricity prices reflect natural gas price trends. The market clearing price applies to all participants, even though some resources have lower costs. In addition to the energy prices, electricity prices include marginal prices for losses and congestion which are more localized. SoCal citygate prices often impact overall system electricity prices because there are a large number of natural gas resources in the south and they often experience greater congestion.

So this slide is showing some of this behavior and effect. Even after the Aliso event, SoCal border and SoCal citygate prices largely followed each other, as was said before. But after the Line 235 rupture, we started to see deviations between the SoCal border and citygate more frequently and more severe, and that's what you're seeing here in the red and the green lines.

On July 24th, gas prices at the citygate reached $40.00 per MMBtu, the highest in 2018. And on the 7th, there was a second gas peak at $27.00 per MMBtu. And this had a knock-on effect on the day-ahead electricity prices in SB 15 peaking at $250 per megawatt hour and then $200 per megawatt hour, respectively. Just to clarify, these data on this slide, these are daily average data.

So these electricity prices this past summer, they've increased significantly compared to 2017 levels. So this shows a trend line going from January of 2017 all the way through beginning of November of 2018. These tight supply conditions, high demand, high gas prices have driven the high electricity prices that we've seen more recently. The record-breaking temperatures across the state, and particular in Southern California, increased demand. And in the winter, load temperatures contributed to higher demand.

From July to September, average natural gas prices at the citygate increased by 134 percent from the same time in 2017. And this was one of the main drivers that we saw in high energy prices across CAISO. We saw higher average monthly day-ahead electricity prices in July and August this year compared to 2017, and this is shown in the graph. If you look at the period kind of in the middle of this graph, the prices are not nearly as high as on the right side of the graph.

You also see this split in prices and electricity prices between the Northern California prices in orange and the Southern California prices in yellow there. And that spread is primarily due to the difference in congestion and losses because the same higher-priced units in Southern California are setting the price there in those instances.

So across the system, we also saw more frequent day-ahead hourly prices above $200 per megawatt hour. And again, as said earlier, on July 24th the system reached a record peak of day-ahead prices at about $980 per megawatt hour in the hour ending 8:00 p.m.

So that's what we have for the staff presentation. We'd be happy to take questions at this time.

MS. RAITT: Thank you, Simon and Lana.

So we'll move on to our first panel.

COMMISSIONER GUZMAN ACEVES: Mr. Weisenmiller --

MS. RAITT: Oh, I'm sorry.

COMMISSIONER GUZMAN ACEVES: -- just a follow-up question for Lana.

There's a -- you had on slide eight the correlation of what you looked to be the spikes with planned maintenance. Is there anything, any -- not that it -- not necessarily planned maintenance, but are there any thoughts on additional causes for the July-August spike?

MS. WONG: So temperature is definitely a driver. So one of the earlier slides, I pointed out that the price spikes tended to occur during extreme weather conditions. So when it's -- during these extremes, the system is just operating under more constrained conditions. So that's one of the key drivers of what -- of some of these price spikes we've seen, you know, that it's been during extreme weather conditions.

But certainly in this, when we were looking at data for -- I was looking at November to December. And when gas prices hit that $19.00 per aMMBtu range, we're all circling around going why are gas prices this high? What's going on? You know, we started asking questions, trying to understand what's going on in the market. And that led to this discovery about the planned maintenance event. And it does seem somewhat correlated to the price spike that we saw.

MS. RAITT: Okay. Thanks.

So I think now we're ready to move on to the first panel on Southern California Natural Gas Supply. And it is being moderated by Catherine Elder from the Aspen Environmental Group.

MS. ELDER: I guess that's my queue to take it away. Good morning, Commissioners. I'll just say, my mother would be very grateful that I got called Catherine, but you all know me as Katie, so with that, good morning.

We want to spend some time following up from the price graphs, so the story that Lana and Simon laid out, and talk about what folks see going on in the market with gas supply.

So to try to help lay that out for you, I am going to turn this over to Rodger Schwecke from SoCalGas, whose team manages the transmission system at SoCalGas. They're not the folks who order gas supply in for customers. Rather, they're the folks who see it come into the system and operate the system to deliver it, which means that they're in a position to see how nominations are changing on a daily basis; what kind of fluctuations and activity did they see on the system?

And then I always -- if I say Evie, it comes out as "Evie Elser" Kahl (phonetic). That just proves how old I am and how long I've known Evie. She represents a large group of customers, who are also gas suppliers. So they experience -- they nominate gas on the system, they sell gas on the system to customers, so they're in a position to have observations about what we see going on with gas supply.

So with that, I'm going to be quiet and Rodger is going to talk.

MR. SCHWECKE: Thanks, Katie. And thank you, Commissioners. I appreciate having the opportunity to talk here and then answer some questions to maybe add some clarity around some of the issues that Lana and Simon mentioned from our perspective, from an operator perspective.

I want to kind of go back, I think that it was mentioned in the presentation, to the cold period that we just had January 2nd through about the 5th or 7th, and to look at those days and what transpired. I think if you look at the graph up here you'll see, where our receipts come into the system is the orange bar. Those receipts were below what our receipt point capacity was at the time. How much of that was attributed to the holidays? And then you had -- you know, a Monday is typically a day that people will schedule gas on the Friday before. Here we had January 1st, so you had a period of holidays, and whether that made a difference in how much receipts we were getting.

But we started seeing demand on our system grow fairly large. And if you really look at the amount of gas that was used, we were exceeding demand on our system, what would be on an hourly basis the equivalent of a 4.8 BCF day. Well, the demand on our system was very high on an hourly basis. And as you could see, we started to withdraw gas. And we felt that without the use of Aliso Canyon, we could not meet demand.

And going through the Aliso protocol, one of the first steps is to work with the balancing authorities, CAISO and LADWP. And that's where we requested of them for a voluntary curtailment, can they reduce their load? We really did not expect that CAISO and DWP would be able to help much. Their load was very low on the system already. It was probably at lows that, you know, we probably don't even expect. It was probably, you know, somewhere around the 200 to 250 million cubic feet a day, so it was a small portion of the entire load. We did really not expect them to be able to provide, you know, a lot of gas to help the situation.

And that's when we began withdrawals from Aliso Canyon and continued those for, you know, almost three days. Over the period of the three -- two-and-a-half days, we withdrew about 1.2 BCF of gas at Aliso Canyon.

I would also say that on an hourly basis, and I mentioned the demand in an hour, the hourly demand -- or withdrawals from Aliso Canyon were, at times, exceeding a billion cubic feet a day equivalent. But when you look at the hourly amount, that really played a key part. And you can see where it peaked during those morning hours. It was really the critical part for Aliso Canyon, let alone across the entire period of the withdrawals.

We, basically, actually did expect weather to occur on Monday of this week. That weather did not materialize. We had a voluntary curtailment on Monday. But the weather was, what we had forecasted, probably about 400 million cubic feet a day less than what we had forecasted earlier on Friday and Saturday, so that actually helped. And receipts -- you know, demand now is running more at the typical level, 2.8, 2.9 BCF. We're still withdrawing gas, no doubt about it.

And I think when you look at the event, as I mentioned, some of the forecasted demands that we had, the actual use, we also relied heavily on our other storage fields. And the inventory levels, we pulled out over 6 billion cubic feet out of those fields over a nine-day period.

The impact that has on a going-forward

basis is that our withdrawal capability at those fields is diminishing. We're probably below 900 million cubic feet, probably approaching 850 million cubic feet of capability withdrawal out of those fields which, looking forward, the use of Aliso Canyon may be more needed again later in the winter. If you look at last year, the coldest weather we had was at the end of February.

So that's where we sat on these days, the period from the 26th of December to the 4th of January. The use of Aliso Canyon was critical in meeting the demand. Demand was fairly high and it continues to be above our receipt-point capacity.

We talked about demand response. And I apologize, this slide is very small. We did use our two programs we have. One is our DialIt-Down Program, which is similar to the Smart Flex Alert Program. It's really a campaign to get people aware of the cold weather and to turn the thermostats down. We don't have much data on what the impact on that is. It's really the first time we even used it.

We did also institute our demand

response, which is our Smart Therm Program where we actually have the manufacturers turn the Smart Therm down, thermostats down, by four degrees. Of the some-odd 10,000 registered customers we have in that program, we probably got about a 50 percent activation. In other words, there's some you can't contact, some that they override, some that, you know, really are partially overridden.

In that, when you look at the amount of gas that was saved during that period of time, it's relatively small. And, you know, so you're talking about 5,000 thermostats turning it down four degrees. Our estimate right now, and these are only estimates, we're going to have to provide the information, but it's less than a third of a million cubic feet of gas. So it's not that much gas savings that we are able to achieve through the demand response at these levels of people signing up to the program.

One other thing I wanted to bring it up, this kind of change, and we talk about a lot of change, but has not been mentioned. The capacity rights on our system, I think what we've seen, and once we had the incident on Line 235, there was capacity available on a firm basis at that time. A lot of people went out and bought the remaining firm capacity that was available.

And I think as you can see when you look at the period, while the percentages don't change much on the total annual, really, if you look at the July through September period, if you look at the amount of capacity that's being held by what I have titled Core and Non-Core Balancing Agents, those are people that have customers, whether they're core customers, non-core customers. And then we have those that are just the core balancing agents which is, you know, almost -- most of that is made up by SoCalGas' Gas Acquisition Department. And then you have those that only have non-core customers as balancing agents. And then you also have customers that have purchase capacity that are not balancing agents. In other words, they're not associated with the customer.

And you could see that when you look at those summer periods that we talked about, there's been -- there was a large uptick between '17 and '18 on people that held capacity. For the first column, you can see it was probably about a 40 percent uptick, if not larger. I think, you know, people saw the outage, they basically saw the capacity available, they prudently went out and bought that capacity to ensure themselves the capability to move gas from the border to the citygate.

I think that really resonates, for me anyways, that you also still have a large portion of capacity, somewhere around 50 percent of the capacity being held by non-balancing agents or people that aren't currently associated with the customer. They could be selling gas to customers; we just don't have that association in our information.

The question was also raised where the OFOs work that we have in our system. And it's clear when you look at these two graphs, over the 2018 period, this is average numbers, that going from a Cycle 2, in which we call an OFO, for a Stage 3, you can see that it goes from a negative imbalance on average to a negative imbalance of about 225,000 decatherms (phonetic). So there is an uptick. It changes people's behavior. It brings more gas on the system. I think when you go into a Stage 4, you're getting to see that the line is higher and that we do see that we actually get a greater increase. I think people will say that that's driven by the price; it could very well be.

But there is an impact when we do call OFOs that we get more gas in the system. And I think when you look at some of the periods that we talked about, 2018 in the summer, we were short in excess, like on July 23rd, 2018, we were short in excess of about a half-a-billion cubic feet of gas on a receipt versus estimated burn basis. We called the OFO and that changed. And, in fact, on July 24th the supply picture changed so much that there was no OFO.

Interesting how the market reacted. There was still a pricing increase on the 24th and that was the high price, but we were not in an OFO on that day. Now a lot of it happens the day before and the day of, so -- but I just wanted to point that out, that we do see a dramatic increase in supplies when an OFO is called.

One point I would like to make, and I think I saw some of the other presentations, we have had a lot of OFOs, there's no doubt about it. Since December 2015, we've had almost 300

OFOs. What I would like to point out is that's all done based on a calculation and estimate of available capacities and hourly withdrawal capacity on low OFOs. Had you taken that same look with Aliso Canyon in the calculation, we would reduce those overflows by about 80 percent.

So there is a dramatic impact when you start looking at what's driving gas prices if it's OFOs. One way to do it is not have OFOs. And we could actually have a dramatic change in OFOs just by using the capacity in the calculation of Aliso Canyon. But Aliso Canyon can't be used as a market tool.

So the one recommendation that -- you asked for recommendations that I have -- that's something that can happen quickly is to actually be able to use Aliso Canyon as a market tool as participants can use that capacity to meet their demands, to meet their swings. It will clearly reduce the number of OFOs. And, really, it brings additional supply into the marketplace. That could happen, you know, up until the pipeline capacities are back in service.

I look at it as this is an immediate thing that can happen quickly. There's no additional decision that has to be made by the Commission but it's something that could be looked at. And I just put that out there as a possible recommendation for us to look at.

And that's all I've got, so if there's any questions now or later?

CHAIR WEISENMILLER: I've got a couple before we go on. I think just focusing on the pipelines for a second, the 235, 3000 and 4000, how old are each of those pipes?

MR. SCHWECKE: The 235 pipe is a 1950 vintage pipe. And I think 4000 is around the same age, along with Line 3000. They're all basically around that 1950s vintage.

CHAIR WEISENMILLER: Yeah, so they're pretty old. Yeah.

We've had the conversation a couple of times, you know, in the Aliso workshops, just in terms of what can we do to get them back online? What's your estimate? And again, it comes back to, I think each time, you still don't know.

MR. SCHWECKE: Well, at least we have been able to begin work on Line 235.

CHAIR WEISENMILLER: Um-hmm.

MR. SCHWECKE: We just recently received

our permits from the California Fish and Wildlife to perform work in the streambeds that we have to work in. So we're looking that that line will come back into service at a reduced pressure because it did have a rupture. Our plan is that we will have to run an ILI or a pig run through that line just to make sure everything's safe before we were to feel comfortable in bringing it back to its original pressure.

When you look at Line 4000, we have a pig line run on that line. We have to do some validation digs on that line. And a validation dig is you get the tool that runs through the pipe and it tells you, you have an anomaly, but you have to go and dig it up and validate it to make sure that the tool is giving you the correct reads. Even though those pipelines are 1950s vintage, we have seen a lot of issues with regard to how the pipes are, you know, holding up over time in those areas in the desert.

CHAIR WEISENMILLER: Do you -- going back on the basis question of looking at this winter, is there any reason to think any of those lines can come back?

MR. SCHWECKE: For this winter?

CHAIR WEISENMILLER: Yeah, this winter.

MR. SCHWECKE: No.

CHAIR WEISENMILLER: No? Nothing can be done to move it?

MR. SCHWECKE: We're moving as quickly as possible and we have probably a timeframe that is working. We don't want to work out in the desert where unsafe for our workers.

CHAIR WEISENMILLER: Right.

MR. SCHWECKE: And our schedule we have is pushing that envelope and we don't expect to have that line back into service until sometime in the spring, probably the April timeframe.

CHAIR WEISENMILLER: And they are still all on rate base?

MR. SCHWECKE: Yes, they are.

CHAIR WEISENMILLER: Okay. Next question is in terms of when you see -- in terms of the pricing spikes, is there anything you can do as a transmission entity to reduce prices, other than the Aliso option you've thrown out?

MR. SCHWECKE: From an operator, from a system operator standpoint there's not much we can do. We have made all the capacity available that's available to the market participants. We do, on a reliability basis, use our storage assets but we can't push gas. We deliver gas out of the storage fields to meet demand. We don't necessarily have the ability to change that, to change the price structure and the prices.

CHAIR WEISENMILLER: And --

MR. SCHWECKE: We don't have that ability.

CHAIR WEISENMILLER: -- and maintenance scheduling; I mean, do you have any flex, or you don't? I'm assuming, when it's bad you only do it because you feel like there's a reliability or safety issue?

MR. SCHWECKE: We have, over the last three years, been pushing off maintenance, pushing off the activities. And we try to schedule those at periods of time when we see the lowest demand. From an operator's standpoint, we don't want to disrupt the demand.

The outage that was talked about at Wheeler Ridge was a relocation that we had to complete. That was the period of time when we thought we could complete it, so not have to do it during the middle of the winter, right --

CHAIR WEISENMILLER: Yeah.

MR. SCHWECKE: -- or into the summer. So that was, we were looking at it from a reliability standpoint, not a price standpoint.

CHAIR WEISENMILLER: So the next question is in terms of do you have an assessment of what's driving the price spikes? Is there any difference than what you've heard from our staffs?

MR. SCHWECKE: No. It's a supply and demand issue. And, you know, that's all I can look at it from my perspective. I can't speculate on who's doing what in the marketplace or not doing. That would be my only perspective, so I'd have to look at it that, you know, if we had more supply in the system, I would expect prices to reflect that.

CHAIR WEISENMILLER: Okay. But your bottom line is you agree with the conclusions we've heard so far on that topic from the staffs?

MR. SCHWECKE: There is a couple points I would like to make --

CHAIR WEISENMILLER: Sure.

MR. SCHWECKE: -- that when they looked at the mitigation, I think there was some item about Otay Mesa. Otay Mesa is not an additive to the Blythe capacity. Those numbers have to be consistent. And they don't just add straight across. Any gas that comes into Otay Mesa takes gas away from Blythe.

There was also a comment about the Blythe capacities. What we have seen in our Ehrenberg capacity coming through Blythe is that area, our southern system, is now dependent upon demand for capacity. Our demand levels are such that we can't take any more gas than the demand, plus what we can move into the L.A. Basin. So there's a limiting factor. And we're seeing, and it could be a lot with regard to the electric generation load, is that we're not seeing electric generation load on our southern system, so we can't take as much gas in. That's why it varies on a daily basis. We're trying to maximize it based on our forecasted demand on our southern system.

CHAIR WEISENMILLER: Right. The last question I have is, obviously, on the non-Aliso storage, capacity has been reduced substantially. And as you indicated, future cold spells would mean, you know, you'd have to shift more to Aliso in that circumstance.

Assuming average weather, how long do we have before you start dipping more into Aliso?

MR. SCHWECKE: I'd probably say Monday, last Monday. We're at a point where we have presented what we feel are minimum storage levels that are non-Aliso storage fields to be able to meet core reliability demands, and I'm talking core customer reliability demands for February. We're very close to those numbers already. I think what we're looking at, and I think it's consistent with the protocol, is to actually start using Aliso Canyon to preserve that inventory, to preserve the minimum withdrawal capability of those fields. And I think we're at that point today to start that process.

And when you look at our Playa del Rey storage field, we're actually working to inject gas into that field to bring that capacity back up because it's those hourly demands that really concern me, that we cannot meet a 4.8 BCF-equivalent day demand if we keep going at the rates we are at our non-Aliso storage fields.

CHAIR WEISENMILLER: Yeah. How much opportunity to have to replenish those fields in this time of year?

MR. SCHWECKE: Well, if I -- I think I have considerable opportunity if I had the ability to withdraw gas from Aliso Canyon and then inject gas in the other fields. Because Aliso Canyon is sitting with somewhere around 32 BCF of gas. It has withdrawal capability in excess of a billion cubic feet a day. So to move 3, 4 or 5 BCF from that field to our Honor Rancho and Playa del Rey storage fields, that's a good tradeoff. I don't lose much withdrawal capacity at Aliso Canyon but I gain a lot at Honor Rancho, so that's the tradeoff.

CHAIR WEISENMILLER: Yeah. I was just trying to understand if there's any opportunity without Aliso to replenish?

MR. SCHWECKE: I think when we look at it, that our average demand, even in a mild -- if you were to look at the December temperature, and this is December of 2018, and use that number, it's about 2.8 billion cubic feet a day demand, 2.8, 2.5. With receipts of 2.6, you're on withdrawal every day.

COMMISSIONER RANDOLPH: I had a question about Lana's slide nine where she talks about the flowing capacity in the pipelines. I just want your thoughts on the question she raised about whether there was adequate supply in the -- flowing supply in the pipe?

MR. SCHWECKE: Well, and this is where I brought the issue because you've got the two lines we talked about, the addition of Otay Mesa, so I'll just look at the second line, the lower lines.

Customers will bring in gas, and you'll have an opportunity to ask, you know, some of the participants, our participants, to meet what their demand forecasts are. Do their demand forecasts change? Yes.

We're at, actually, a fairly high, I think, utilization of our receipt-point capacity. But, and I may sound like a broken record, but we -- also, the customers don't want us to flip into what would be a high OFO, where we have too much gas in the system. So they're trying to manage their supply deliveries.

We're at a fairly high receipt capacity percentage utilization. So -- but the numbers are what the numbers are. As you can see, when we got people back, that you did have an uptick in supplies coming into the system. And we're still running at about 2.5, 2.6 BCF in receipts. We're fairly full.

PRESIDENT PICKER: Can you -- what can you tell us about growth and demand across the last calendar year and what do you expect in the next calendar year, or if you have a different calendar you're using for measuring?

MR. SCHWECKE: Yeah. I think from a demand perspective; we don't see much growth. I think we actually, on an overall basis, probably see a decline. And it's probably experienced by the decline in electric generation on our system. Now whether that generation has just shifted to Northern California or outside the state, I don't know. But from a perspective, we probably see less demand on our system on a going-forward basis.

PRESIDENT PICKER: So some decline in demand from electricity. Do you see growth in other sectors?

MR. SCHWECKE: No. We -- you know; I really don't know. That's not my area. We have not seen much demand growth in other areas. We do see continuing new business but nothing abnormal, growth-wise. I think it's offset a lot by just, you know, energy conservation, building standards, tighter homes, tighter envelopes, individual customers use less, so we're seeing that offsetting any of the demand growth.

PRESIDENT PICKER: And given the limited experience you've had with your demand response programs, which is kind of a timebomb reduction, do you see any opportunities to actually improve or increase the overall effectiveness of those programs? Is it a pricing issue? Is it an experience issue? Or is it a lack of suppliers who really are proficient in this area?

MR. SCHWECKE: Again, that's not in my area. I think we see, you know, the numbers of the 10,000. I can't really say whether we can actually increase it or not. No, I'm worried about operating the system. Others are looking at the demand response area.

COMMISSIONER GUZMAN ACEVES: Just a couple of follow-ups on Line 235. You -- what other variables do you have in constraining the repair? You mentioned the Fish and Wildlife permit. Is there --

MR. SCHWECKE: Well, so we got the Fish and Wildlife permit. And it's basically just the amount of work we have to do. And when you're working out on a right-of-way out in the desert, you basically have what could have a four- to five-mile drive every day to and from the worksite across the desert, across right-of-ways in which you can only drive five to ten miles an hour. So just the ingress and egress eats into a good part of your day. And a lot of that is because of, not as much during the winter, but when we start getting into the warmer months, it's the tortoise habitat and not being able to drive the right-of-ways any faster than that.

COMMISSIONER GUZMAN ACEVES: And so what is the timeline now?

MR. SCHWECKE: We're expecting to have the Line 235 back, if everything goes well, sometime at the end of April.

COMMISSIONER GUZMAN ACEVES: Okay. So your proposal to hedge with Aliso is in duration until April?

MR. SCHWECKE: Well, I think when you look at it, because we have to -- this is what concerns me, we have to then, at some point, run an ILI, in-line inspection tool, through Line 235. Anytime we run one of those it worries me that we find an immediate condition in which we have to take the line out of service.

We also have Line 4000 in which we have to do validation digs. We have to take that line out of service to do those validation digs. I would think that probably more like through the summer to make sure that we are ready to go is probably the more likely timeframe to have that available is summer because I think when you look at electric generation customers, they want that ability to use that storage during their peak period. Well, they have to have the opportunity to put gas into storage to be able to use it in the summer. So knowing that it would flow through the summer period could be beneficial.

MS. ELDER: Any other questions? Then we'll, yeah, we'll pass the slide clicker thing-a-ma-bobber, which is a technical term, and Evie will take it from here.

MS. KAHL: Thank you. Good morning, Chair Weisenmiller, President Picker and Commissioners. I'm here today on behalf of the Indicated Shippers and the Energy Producers and Users Coalition which is, essentially, a group of overlapping companies who are large users and producers of natural gas and electricity, and also get engaged in the marketing of natural gas. So in order to prepare for today, they prepared me. I spoke with each of them individually for the antitrust reasons Lana mentioned. So what I'm going to provide you is kind of an overview of the picture that I got in terms of a common message.

And the most common message doesn't come as any surprise to you because I've heard it several times already today, which is it's the supply-demand balance.

Aliso created some very challenging and, in fact, threatening conditions. But it is the pipeline outages and the supply constraints that threw the market into a spin, and I'll show you a picture of that shortly.

And while the problem seems pretty apparent when you look at the numbers, the solution isn't, and neither is the urgency for the solution. So I'd like to get to that at the end and talk about what are we doing about pipeline maintenance.

But I wanted to start with a little perspective, back to 2006, and Chair Weisenmiller will remember this, 2005, 2006 the Commission, the PUC, was looking at the question of how much slack pipeline capacity do you need in order to have supply diversity and in order to have, you know, active price competition? And at that time, SoCalGas' position was that you needed 25 percent more than your average year's demand. And if you look at that today, that's probably around 3.3 BCF, I think. And at the time that the Commission made that assessment and SoCalGas made those comments, they had Aliso Canyon in full operation, so we had all of Aliso Canyon. And even then they said to have active price competition, you needed to have 25 percent slack capacity.

And I guess I'll start with the first slide here. And look, if you look in the lower left corner, what you see is what happened to our capacity. Starting in January of 2015, combining receipt-point capacity with the storage withdrawal, we were at 7.6 BCF. In October of '17, we were down to a combination of 3.5. And now we're around 3.9, so we're far, far, far below what the PUC said was adequate and what SoCalGas said was adequate for price competition.

And up on the screen right now I have a map. I think you saw one earlier that looks something like this. This is not a slice of time, it is just kind of an overall view of receipt points and constraints on the SoCalGas system.

So the green arrows are the receipt points and you see there are many of them, which is a good thing because we have a lot of supply sources coming into California, but it can be a hard thing for those sourcing gas. If you have a maintenance outage or other condition on one of the pipelines and you were planning on sourcing your gas from that pipeline, now you have to go rearrange your supply when there is an interruption or when there is a reduction in capacity. So your regularly seeing folks behind the border trading to try to keep up with what's going on with maintenance, outage and supply constraints. So that's part of what goes on. And there is a cost to that activity.

The red crosses or Xs are the constraints on the system. And those aren't the constraints today necessarily, but I wanted to give you a feel for the pervasiveness of the constraints and the outage problems on the system. It's

California production from time to time, it's the northern zone, it's the southern zone, it's everywhere. This isn't an isolated problem.

So I wanted to talk a little bit about what the picture looks like when you put all together on these constraints with supply and demand and the price spikes.

So first, what you see before you right now, that blue line is supply capability. So it is kind of a combination of pipeline capacity to the extent that there's supply behind it that is available to the market at any time. And you can see, it changes markedly over time. And, obviously, more recently there have been some very significant changes.

The next line is demand over time. And so you can see, there are all kinds of different spikes and demand that are going on. At the same time, our capacity availability is changing.

And so if you look along that top line, you can see pre-Aliso Canyon, some of the things that were happening. And what you see in prices is the prices, the red line here, they were fairly stable, despite the changes in capacity and supply and demand because there was still a healthy difference between the supply and demand, and that's the white area between the blue and the green.

But as you see, the supply constraints start coming on with Aliso Canyon Line 3000 which was a two-year outage, Line 4000 and 235, which is -- we're at 16 months at this point. That's when the problems arise. And what you can see is that white area between the supply availability, the blue line, and the green has almost collapsed. And so, not coincidentally, that's when you see the price spikes happening between the citygate and the border.

So from the perspective of our group, it's a supply-demand problem, which is what Rodger said. It's very clear that it's a supply and demand problem.

And in addition, we're talking about a lot of things today but the solution seems fairly obvious, too, and I think Chair Weisenmiller has been hinting toward that, look when the problems arose, Line 4000, Line 236-A. The simple solution is fix it, just do it. And I'll get to that a little bit, as well, in terms of, you know, what's really going on here.

As I said, when you look at the Line 4000 and 235A outage, it's been about 2 years, I guess not 2 years, 16 months, and it was 2 years for Line 3000, and I want to compare this with what happened on the Enbridge system in British Columbia.

In October of 2018, Enbridge had a rupture on their pipeline. It was a 36-inch pipeline, so SoCalGas' is a 30-inch pipeline. It was in a very rural and remote area. And lo' and behold, Enbridge managed to repair the rupture in 30 days. Granted, they didn't bring it back up to full capacity in 30 days and they're still working on that, but they repaired the rupture in 30 days in a rural area on a similar pipeline.

And so the question is: Why is it taking us 16 months, 2 years to get these repairs done? It's, from the outside, without any inside information, it's very, very puzzling.

And I think another point I wanted to make is it's puzzling because we really don't have any information. I think it was illuminating, Chair Weisenmiller's questions today, about what is going on.

But another problem is the amount of

information that is available to the market. And that information is critical because they're making decisions about how to source supply, so they're always looking at what's going to be available and what's going to be constrained.

And today, what we have available in the market is a daily maintenance schedule that SoCalGas posts. And on there they post the line, the start date of maintenance, and then the end date of maintenance, and then a description. Virtually all of the end dates on the maintenance schedule are TBD. So what you see is you may have a start date and that start date may or may not hold and you have absolutely no idea when that line is going to come back. And if you look at the descriptions that they provide, you know, I'm looking at one restriction where we're talking about 4000 and 235, it says, "Restricted operation of Line 4000 and Line 235 outage." That's the message. That's all we know.

And so you've got a whole market sitting out here trying to figure out what to do, where to source the supply, where the constraints are going to be, how long they're going to last, and that's what we get for a message. We don't have any information.

And I'm going to come back to Enbridge again because when Enbridge had their rupture, if you go back and look at what was going on there they had, I think I counted nine notices between the time it occurred and the time they completed the repairs. And this notices, they were providing information, like we are building an access road so that we can get to the site. That was one of the messages. Another message was we're laying down construction. They're giving very detailed information about what's actually going on in the project.

We don't have any of that. We have very little information about what's going on with 235. And rumor has it, nothing is going on with Line 4000. So we sit out here and we wonder, when is this problem going to be solved?

And I think there has been a lot of expression that we've dodged a bullet over and over and over again. But the supply-demand imbalance is so tight and the system is so exposed that we can't really afford any upstream interruptions on upstream pipelines. So we are really kind of living on the precipice here each and every day. And for the businesses that I work with that are running refineries or running oil and [gas] production, that's threatening; right? Because the supply reliability is critical. And as we see in the electric side, as well, it's very, very critical.

So in terms of what can we do about this? I think the first thing is, and I'll ask Rodger, better communication. Let's start to provide more information. Let's provide regular information on your outages in terms of what steps have you taken? Where are you in the process? Where is permitting?

And then the second point, I'll say it again, just do it. I mean, at some point here it's starting to look strange that it's been this long and we can't get it fixed. With all the talent in this room and all the resources, if it's a permitting problem, we can fix that; right? You can fix that. If there is a workforce problem, that can be fixed. There are all kinds of problems that could be there.

I would suggest we also think about whether there's an incentive problem here. You know, to date, it is the end users that are bearing the costs of all of this. It's not SoCalGas. And so the query is: Is there enough motivation for SoCalGas to complete these repairs since they aren't feeling the same pain their customers are feeling?

So I guess those would be our two requests, is better communication, and let's just do it. Let's just get this done.

Thank you.

COMMISSIONER DOUGLAS: So I have question, and your comments were a really good segue to it. I'm actually going to ask the question or make a comment more to SoCalGas. But you know, I have seen a lot of permits and a lot of permitting processes. And I'm very familiar with the fact that, as you say, there are things you have to do when you have a permit, and there are timeframes and sequences. And sometimes there are seasonal challenges and requirements, and so I'm aware of all that.

And at the same time, I have, in my time on the Commission, sometimes seen permitting or permitting agencies kind of held up as a reason for delay. You know, when you really, really look at nuts and bolts, either it really kind of wasn't or there were problems that could have been solved with proactive action or asking for help or basic coordination and things that we know how to do.

So I'd like to invite you to comment on that. But I'd also be very interested in a more detailed conversation, maybe subsequently, about the permitting requirements and timelines and how you see yourselves able to potentially accelerate schedule and keep the schedule?

MR. SCHWECKE: So, excuse me, you asked a lot of questions -- or in your statement. You know, we started the -- once we knew the work that we had identified, you know, we started the permitting process. There are multiple agencies. I only mentioned one, which is the last one. And we actually went to them and they have their timeframe for review. They have their requirements. When they came back with their initial response of the permit, it would, basically, probably not allow us to do the project.

We have now accepted conditions of the permit. They're probably precedent setting. In other words, I'll give you an example. We have to stop work in any wash when the forecast of rain is 20 percent.

So when you talk about getting out there and mobilizing and demobilizing, to be able to go out there and then all of a sudden you have a forecast of 20 percent rain, you have to stop work and you have to leave the site.

So that permitting process extends for six to nine months, that's if we don't have to have a CEQA requirement. This is a repair, emergency repair.

So that's -- I don't know if I'm answering your question or providing a comment, but it's just, it's frustrating for us when we have put together a plan and mitigation for the potential issues that we have used in the past.

Another example is that we used to be able to file for an individual incentive project. In other words, if we had, you know, 20 creek crossings, we could add for one project. Now we have to submit 20 different ones, one for each of the creek crossings.

So there's a lot more, as far as the requirements, that we have today than we've had in the past and they've become more and more onerous.

COMMISSIONER DOUGLAS: So that's helpful and it's also anecdotal, and understandably so. You weren't necessarily expecting the question. But it would probably help me to have a more detailed understanding then of, again, timelines and the big picture on that.

We have, and a number of us on this dais right now, lived through some pretty detailed work around permitting and I think we have an understanding of that. So on one hand, I hear you, that you may have encountered some conditions that you consider onerous. And at the same time, you know, this is a high priority and there are sometimes, you know, there are -- I guess I don't have a good enough sense of the big picture from the examples.

MR. SCHWECKE: Yeah. And maybe we can take it offline and we can talk --

COMMISSIONER DOUGLAS: Sure.

MR. SCHWECKE: -- more about some of the issues around that.

COMMISSIONER DOUGLAS: Sure.

CHAIR WEISENMILLER: Yeah. Um-hmm.

COMMISSIONER RANDOLPH: Can I just follow up on that a little bit? Because it's -- you know, there's obviously going to be permitting issues. But then what about your workforce? You know, what are the opportunities to just increase the pace of work by making sure that you have an adequate workforce? As you're moving forward with each segment, are you able to effectively do the work as soon as you're permitted to do it?

MR. SCHWECKE: I would say, yes, we are. Most of the work that is being done is done by contractors on these types of projects. And we have maximized the amount of contractors we can use within the limited space we have and the limited ingress and egress we have. So we've maximized those resources.

We are working what is limited hours because it is unsafe to be working in the desert, necessarily, in these type of projects during the nighttime hours. Also, you end up with contractor fatigue.

We're not having an issue with resources. We are maximizing those and we're accelerating those. We have multiple locations and sometimes, at those locations, we'd actually delay work if we tried to bring more people on.

CHAIR WEISENMILLER: Yeah. I still think that it would be a good opportunity to see if the PUC and permitting folks, the Energy Commission permitting folks could figure out a way to expedite some of the permitting. Now you're pretty far down the path but, you know, let's at least try.

COMMISSIONER RANDOLPH: Oh, we have made ourselves very available in terms of working with other agencies and asking for help. So I don't think they -- I hope you're not saying that we haven't been because we definitely have been making ourselves available in terms of trying to facilitate the back and forth. So I'm not sure that's really the issue.

MR. SCHWECKE: So we did come and ask for assistance. That assistance was then directed to the Governor's Office. Whether that assistance allowed us to get the permit now, had we not had that, it would have been more months. But we did come to try to work on everything internally to try to move that forward. So we're just happy to have the permit now that there is not any delay. And we've actually accelerated work because our original plan was to end in, you know, the April timeframe. And as we were delayed really starting the work, it’s been about six weeks, I think, now, but we’re still accelerating the work as much as we can to get it done in the April timeframe.

MS. ELDER: I thought I’d jump in with one little question.

Rodger, remind me, there’s still non-balancing account treatment for non-core throughput, isn’t there?

MR. SCHWECKE: That is correct. We are completely decoupled from throughput with regard to our (indiscernible).

MS. ELDER: And, Evie, you were talking -- we were talking earlier a little bit about some of your clients and their experience with maintenance of really important, reliable facilities and how they do that and how it seems to be kind of different than what we see in the maintenance notices on ENVOY. Could you elaborate a little bit?

MS. KAHL: I think what you may be referring to is the discussion we had about risk management and safety. And I think that’s something that the CPUC has been working on since

San Bruno, so we're eight years out now. And there's been a lot of proceeding going on around safety, risk management, reliability and planning. And the question is: With all that's taken place, with all the encouragement, with everything that's been going on, now is it that today we're still in a position, you know, looking back at the map where we have all these different outages coming up and difficulty resolving them?

So, I mean, we're supposed to have a risk management system that allows forward-looking management of these problems. And so do we need to take another look at that? Is it working properly? Is it enough? I think that was the point I made.

MS. ELDER: Right. And I realize we're over our time allotment.

But, Rodger, I thought I'd ask, when you bring 235 back on, and you think that's going to be in April, you then have to do some ILI work. And could you remind the Commissioners how long it will usually take to do the ILI? And then I think you have to wait to have a report to come back. Talk a little bit more about that process.

MR. SCHWECKE: So every time we run an in-line inspection tool, or commonly referred to as a pig, we basically get an initial report. To actually run the toolis probably a day or two at the most, assuming you get good data as you run the tool. The issue we have is that you get a report back from the vendor fairly quickly on immediate conditions, in other words, if something just jumps out. An immediate condition is where you actually have to take action immediately and that is, either reduce the pressure in the pipe or taking it out of service, and then fix that immediate condition. And then several months thereafter you get the full report which identifies the anomalies along the pipe.

Think about, you know, thousands if not tens of thousands of datapoints that you have and it identifies anomalies that now says you have a, an example, a wall loss of 60 percent. That’s not necessarily an immediate condition based on the pipe and pressure. But what it amounts to, it says, well, that tool says it’s 60 percent. Is the tool within its tolerance? Because I think what we’ve seen on Line 235 in some of the validations was the tool was not in tolerance.

The tool was reading anomalies, missed anomalies by 10, 20, 30 percent. And when you have a situation where you have a 60 percent anomaly and if that tool tolerance is outside 30 percent, that's a 90 percent. That would be an immediate condition.

So what's we're finding and it's really for the pipelines in that north desert zone, that's where we're finding the tool tolerances just aren't living up to what the vendor specked it; elsewhere it is.

So that's what has drawn a lot of concern because the issue with the potential for rupture is great. And we're using, you know, various risk management tools and risk ranking and looking at what is the probability that we could have another incident? And some of the numbers that we're getting back are very disturbing for me to bring that line back into service. Fortunately, enough, on Line 235, no one got hurt. Very, very fortunate.

So I'll leave with that.

MS. ELDER: And when you are done with Line 235, do you by chance have a sense of how much of 235 will have effectively been replaced?

Are we talking -- I don't know if the problem is just with the little segment that ruptured or is there work further along the line, along the right-of-way, that sort of thing?

MR. SCHWECKE: Well, you know, that whole section of Line 235 is about 50 miles, give or take. I think we're, in this whole process, probably replacing-- I'll have to check-- but it's several miles of pipe because of the rupture anomalies we've had. It's different. It's not one section of pipe, it's several different sections.

COMMISSIONER GUZMAN ACEVES: Can you just -- one follow-up question.

Based on what was just said and certainly the worst case scenario, a question for Evie, are some of your clients, particularly some of the more lucrative ones, like the refineries, actually stepping back and seeing, given the amount of expenditure on these higher cost of electricity from these gas prices or other costs that you're using gas for, are you looking to switch your fuel to a different non-fossil-based source, which may be ironic for the refineries? But is that something that you're stepping back from, given this uncertainty and fluctuation?

MS. KAHL: Yeah, I can't speak for their internal thoughts about what they're planning or looking for at the refineries. I can say that it effects the use of alternate fuels, which is refinery-produced gas. Certainly, there's more use made of the refinery-produced gas. But with respect to future plans, I can't comment.

COMMISSIONER RANDOLPH: Can I ask one more question?

This is a question for Evie and her chart with the -- that illustrates the price spikes. And this is more of an educational question of trying to understand why you do see gaps where your demand is still high and you're still limited in your capacity but the price is not necessarily high. Like explain. Can you kind of walk me through?

MS. KAHL: I really wish I could --

COMMISSIONER RANDOLPH: Okay.

MS. KAHL: -- but I'm already beyond my comfort zone as a lawyer.

COMMISSIONER RANDOLPH: Okay. That's fair.

MS. KAHL: What I can say is I know there is some lag in the behavior sometimes to what's going on. And obviously, market information is going to change what you're thinking about those, you know, the supply and demand balance. So I can't really comment beyond that.

COMMISSIONER RANDOLPH: Okay. Thank you.

MS. ELDER: With that, I'm not seeing anybody else pop up with a question, so we'll wrap up this panel.

And that means I'll turn this back over to IEPR boss, Heather.

MS. RAITT: Great. So thank you. And we're conferring on timing for a minute. Okay. Super.

So we'll move on to the next panel, and it is on Natural Gas Price Impacts and Electric Generation Market.

And if you could go ahead and we'll have our panelists come to the tables. We'll have a place for you. And the Moderator is Simon Baker from the CPUC.

MR. BAKER: Good morning, Commissioners. Once again, I'm Simon Baker, the Deputy Director of the Energy Division of the PUC. And the purpose of this panel is to hear from the electric generator community and some of the load serving entities that have been experiencing some of these price effects on the electric side. And this is a really complex set of issues, so looking forward to the expertise of the group to help to unpack some of this for all of us in terms of how these knock-on effects happen from the gas system onto the electric system.

So we'll do an initial round of opening remarks and ask the panelists to please try to keep your remarks to about five to seven minutes, given the time, and then we'll take questions, as well, from the dais. A reminder to everyone to please introduce yourself as you begin to speak.

So we'll start with you, Colin, Mr. Cushnie.

MR. CUSHNIE: Good morning, Commissioners. My name is Colin Cushnie. I'm the Vice President of Power Supply for Southern California Edison. And I definitely appreciate the opportunity to be here today to discuss what's happening in Southern California.

As Simon noted, you know, the interrelationship of the gas and power system is quite complicated. There's a lot of linkages.

But what I'm going to try to do here is keep it simple.

And when I think about the challenges before us, I think of it in three dimensions. The first dimension is the physical system constraints, which there was a fair amount of discussion on just before this panel, and that's the supply and demand tensions that we have today. The second dimension is the scheduling conventions and the impact that the Gas Company's overall pricing structure has on power prices. And then the third dimension is the economic incentives that are presented to electric generators participating both in gas and power markets.

And, Simon, is there a --

MR. BAKER: The clicker is right there. Thank you.

MR. CUSHNIE: So we've already had some discussion around the physical constraints on the SoCal system. The Aliso Canyon field is greatly limited, just really operating for reliability purposes. And there's a significant amount of pipeline maintenance.

And so what's -- you know, moving into

the dimension of how do gas and power scheduling conventions interrelate and impact power prices, if you look at the bottom of the chart here for those that have it, the way the gas system operates is most gas supplies, probably greater than 90 percent of gas supply for electric generators, large shippers, is procured early in the morning, say by 7:00 a.m. for the following days operations. And we schedule that gas on the Gas Company's system by 11:00 a.m.

Meanwhile, on the power side, we are submitting our electric bids to the CAISO at 10:00 a.m. and we're -- and so we have some idea of what gas prices are because we just transacted at the market place, and so we put those gas prices into our bid curves. But we don't know what our actual generation schedules are going to be until about 1:00 p.m. So we've bought and scheduled our gas, over 90 percent of the gas that we're flowing, before we know what our power schedules are.

And the OFOs that get called have been almost entirely five percent balancing tolerances. And for most generators, a five percent balancing tolerance is darn near impossible to stay within electric because there's just so much uncertainty and variability on the electric system. There's a lot of things on the electric system that can greatly change your generation dispatch on a day-to-day basis that may not be knowable by the generator at the time that they're bidding.

So at one o'clock, when we get our power schedules back, we do have an opportunity to try to change our flow in gas supplies. There's four more nomination cycles on the gas system. There's one still on a day-ahead basis at 4:00 p.m.; we call that cycle two. And then the other three opportunities are intra-day opportunities the following day but very, very little in the way of available gas. And your gas supplies are prorated because you're already in the middle of the scheduling day.

So right here, we just have sort of a structural challenge for electric generators to be able to accurately predict their gas burns and flow gas accordingly.

The OFO impact is particularly pronounced when the Gas Company calls or needs to call high-level OFOs. So we saw this in the summer last year. The Gas Company had called what we call a Stage 4 OFO, which meant that if you were out of tolerance, you were going to pay a $25.00 per million BTU penalty. Keep in mind, the average price of gas at the border is running about $4.00, so that $25.00 penalty is significant. It would translate to, you know, let's just say that's a $200 to $250 per megawatt hour price of power. And so generators will be, to the extent that they may have incremental dispatches to the CAISO that they weren't expecting, they'll need to bake that at a very high penalty price into their bidcurves.

And it just sort of becomes a self-fulfilling event at this point in time that the market psychology is concerned about high penalty prices, so you know, the electric prices rise in response to that to prevent dispatch if there's not gas flowing. And customer costs are unnecessarily increased.

A key consideration here, I have it up here there on a bullet point, is it only takes one generator that believes they're exposed to that penalty price to put that $25.00 per million BTU penalty price into their bid curve and for the CAISO to dispatch that resource to now set the market clearing price on that much higher marginal cost of gas. So it could be a very small package of gas that led to tens of millions if not hundreds of millions of dollars of increased power costs.

So I know we're, you know, short on time here, but there are a few times things that I think are also important for the Commissioners and folks here to realize.

There's a number of incentives or disincentives, depending on how you think about it for, you know, how electric generators participate in the gas market. CAISO interconnected electric generators in particular, I refer to them as CAISO EGs, they recover their fuel costs when they are dispatched by the CAISO. So if they buy gas, they only get cost recovery for that gas if they are operated in CAISO's market and get market revenues from the power side.

And so, you know, in a normally functioning gas market, most generators will typically not procure firm pipeline capacity or firm storage because they have a monthly payment that they have to make for that transportation capacity, that storage, that they are not necessarily able to recover through the CAISO's marketplace. If they were to do it, they would be, you know, speculating that they could bid high enough and be competitive enough to clear the market and get enough revenues to collect those costs.

I'd say investor-owned utilities, like Edison, municipalities are positioned differently because, in Edison's case, we have an ERRA balancing account, so we can go out and buy storage and pipeline capacity and recover those costs, regardless of whether the resource operates or not. But Edison controls a small percentage of the gas-fired generation in the Southern California area, so it's the other generators economic incentives or disincentives and their bidding practices that are what really influences power prices in many hours, and therefore exposes electric customers to the shock impact of high gas prices.

Just a few other points here I'd like to make before touching on possible solutions.

When the backbone system is constrained, like it is on the SoCal system and there is no storage available to purchase, we have a broken market, if we want to call this a market. Markets don't function when there's insufficient physical capability to meet all the demand.

And so, you know, despite the fact that, you know, generators are taking all action appropriate, I assume, on a daily basis to flow a sufficient amount of gas, they've become price takers at the SoCal citygate. And so whatever the marketers are able to command for gas prices is what's going to set the market clearing price, and that ceiling increases the higher the threat of an OFO penalty price. So if we're going from a $5.00 penalty phase to a $25.00 penalty phase, that becomes sort of the de facto ceiling that market participants are willing to pay to avoid being short on gas.

A few other points here which just, I think are really important to remember.

We can't assume that all electric generators are necessarily concerned about controlling gas prices. Electric generators are paid at a market clearing price. And so to the extent that they have what we refer to as inframarginal resources, resources that are in the money, having another generator exposed to high penalty price, paying a high gas price, putting it into their bid curve will increase power prices and it will increase the market rents that the inframarginal generators captured. So, you know, it's just another version of the hockey-stick bidding that we saw during the energy crisis. But again, I won't say that it's anyone being a bad actor. Folks are just responding to the economic signals that they have.

At least in Edison's case, you know, Edison, as I mentioned, does not control most of the gas-fired generation in Southern California. We did for a period of time. So these IPPs are now responsible for bidding their generation resources into the marketplace. They are not responsible for electric system reliability. They're not responsible for retail customer cost impacts. So we don't have least-cost dispatch occurring, presumably, on these resources like the utilities do. And I'll leave it at that.

Final, final slide here, and my apology, Simon, we were asked to talk about some of the recommendations for potentially addressing the situation. So recognizing that as long as we have a constrained physical system, we're going to be limited in what we can do to completely address the situation.

But one thing that we could immediately do, and Edison and SCGC have a PFM in front of the Commission on this, is we could reduce the maximum penalty price that we charge, maybe just electric generators if you wanted to do it that way, but that you would charge non-core shippers in the OFO events. The level of price of the OFO does not do anything to change our incentive to deliver an appropriate amount of gas.

You know, Edison in particular has an incentive to have a reliable gas and electric system, we are a utility. And all the $25.00 penalty does is means we'll pay more for the same amount of gas that's flowing at the border if there is, as you saw on some of the other slides, no ability to flow additional gas. All we're doing is saying pay more and more and more for the gas that is available and let's impact power prices through the function of that very high penalty price.

Things we could do in the near term, and I'm happy to answer, you know, questions, you know, in detail on this later, I think, you know, there are a fair number of days where the system is constrained and where, you know, where the core had under-forecasted its gas demand, that will happen. But the gas balancing rules actually prevent the core from trying to bring in more flowing supplies because, in doing so, then they would be out of balance with their forecast, even though their forecast was wrong, their forecast was below the actual flowing supplies. So in the winter when the core is 60 percent of demand and they've under-forecasted their usage, we don't want to have an artificial constraint telling them not to deliver more gas. We want them to actually deliver more gas.

Something else that we can do is, in recognition that the system is constrained, and as regulators, you know, there is an obligation to ensure just and reasonable rates and services, is we could temporarily suspend the backbone transportation system that the Gas Company operates under right now.

What happens today is that shippers, as

Mr. Schwecke said, that had acquired firm capacity on the backbone system, they're the ones that have access to the gas at the border. And then they're the ones that get to set the price of the gas at the citygate. Electric generators which do not have firm backbone capacity, either because it's not available or they don't have the incentive to buy it, can't access gas at the border. They're price takers at the citygate.

So by temporarily suspending that tariff, we could revert to our historical system where all shippers are treated equally at the border and we would just prorate gas supplies as shippers tried to bring gas in.

A couple other very quick things here. There's sort of a nuance in the way the penalty structure works. There's daily penalties for being out of balance and then there's monthly penalties for accumulative monthly imbalance.

Right now, at least speaking for Southern California Edison, when we see that the Gas Company says they have a low OFO, so they need more gas in the system, we will buy us our procurement to delivery more gas to the system. But what that can do if we have, you know, a series of days of where they're low OFOs called and we've over delivered, we will then, on a monthly basis, be considered to have over delivered gas and be subject to a penalty for having over delivered gas.

So I think if we could change those rules to not penalize shippers who deliver gas in a contrary direction, in a way that helped the system be more reliable.

And then finally, as we think about where California is headed, you know, we're hoping to rely a lot less on gas on the electric system as we decarbonize the electric sector. We probably should just really rethink the role of natural gas as a fuel source for the electric sector and perhaps move to a full requirements cost-based gas supply tariff system where we would look to the Gas Company to provide gas on a cost basis -- or cost of service basis, excuse me, and then require electric generators to use that in their burner tip price through the resource adequacy mechanism. That will allow the CAISO to provide better forecasts of overall aggregate gas demand, and for the operator to therefore ensure that the right amount of gas is flowing on the system.

Today, with multiple generators, we're all individually trying to forecast our gas demands and we may collectively over or under forecast because we're seeing the same market signals, and that puts a lot of stress on the pipeline system.

And I think at this point in time, you know, our efforts to decarbonize the electric sector are going to be put at risk if we continue to have small amounts of gas significantly increasing the price of power on the system. It's going to put a lot of stress on other sectors that may have been looking to use electricity to decarbonize their sectors.

So with that, I'll stop. Thanks Simon.

MR. BAKER: Thank you.

Chair Weisenmiller, did you want to go with questions from the dais now or hear from the panelists before?

CHAIR WEISENMILLER: Yeah. I thought, probably, I was going to suggest we go through all of it and then ask questions. I certainly have some for Colin, but probably better --

MR. BAKER: Okay.

CHAIR WEISENMILLER: -- just to roll on.

MR. BAKER: That sounds good. Okay.

CHAIR WEISENMILLER: Okay. Thanks.

MR. BAKER: Kendall?

MS. HELM: Sure. Good morning. My name is Kendall Helm and I am the Vice President of Energy Supply for SDG&E. Thank you for inviting me today. I don't have a presentation or extensive opening remarks, but I'm happy to answer your questions and those that Simon may raise for discussion.

I do want to remind you that I'm here today in the capacity that we -- I oversee the purchasing of gas for our electric generation. So the information perspectives I'll provide are those of a market participant. It's SoCalGas that provides sort of the gas service to our core customers, so that's one important differentiator.

The other thing that I'll just say before we get started is I think at the 10,000-foot level, SDG&E does purchase most of our gas at SoCal citygate for our electric generation. And as such, we certainly are concerned about the high SoCal citygate prices, and we've seen that translate into our power prices.

We do, as others have mentioned here

today, see it ultimately as a supply and demand issue, and that there are a number of structural constraints that have contributed to that -- thank you -- a number of structural constraints that have contributed to that. I don't know that we necessarily see any one structural constraint, like Line 235 being the particular constraint that causes the problem, but much more a host of factors that reach a tipping point, both on the supply and demand side, and that's where you see the price spikes.

Certainly, our access to information as electric generators, whether it comes through the timing of the CAISO bids, information can exacerbate those constraints. But at the end of the day, I think I'm a fan of the idea that the simplest solution is usually the best. And so I think SDG&E would first prioritize what we can do to address some of those structural constraints, and there were a host of factors raised on the first panel. But I think that's where we'd like to first see our actions.

We are open and willing to considering and analyzing different kinds of market interventions to the degree we can't address the structural constraints. But I would remind us that market interventions do require, I think, a good amount of analysis to understand sort of the pros and cons because they typically introduce both intended and unintended consequences, both on the positive and negative, so I'm happy to talk more about that as we go through the panel, but I'll stop there.

MR. BAKER: Thank you, Kendall.

So next, we're going to go to Jan Smutny-Jones.

MR. SMUTNY-JONES: Good morning. I'm Jan Smutny-Jones, CEO of the Independent Energy Producers Association. And we've been around for a very long time under a number of different markets. We represent a significant amount of the independently-owned gas fleet here in California, as well as pretty much one of everything in the renewable sphere, as well as energy storage, so we're pretty active in the energy markets.

I want to say that -- let me get the clicker, wherever that is -- I'm not going to speak a lot off of slides, but I think between some of the early statements that were made with respect to supply issues here, the map that popped up earlier, and I think Evie had a map that showed, I think, three or four different Xs, I took a map out of a presentation that was done in May of this year, there are no fewer than four red Xs which are outages, and there were two additional yellow Xs which were restrictions.

Now if you looked at the map of Southern California as a human body and those pipelines as arteries, there are certain days of the week that that body wouldn't be able to get out of bed. And I think that's the problem we're facing here from the standpoint of restrictions on the system that are causing supply problems for people who are generating electricity in Southern California.

So the -- you can see I'm -- there we go. Okay.

So this is -- Colin's was a lot prettier than mine. This the procurement schedule. And I just put it up there because when I was trying to sort this out in my own brain in terms of who's scheduling what, when, it could be kind of confusing. But the key issue here is that the markets are not aligned and that may not be a problem under normal circumstances. But when the system becomes stressed, that misalignment leads to issues in the following day.

So the California ISO market pretty much, you know, Colin bids his resources in, my members bid their resources in at one o'clock -- earlier in the day, probably at ten o'clock, then we get a schedule back from the ISO at one o'clock and that pretty much tells you what you're supposed to be doing tomorrow. Things change between that time point and when you're actually generating electricity and that's where the pricing issues become pretty significant, particularly as you get into the actual day of because now you have significant issues that could be problematic. That's just a description of what's going on here.

I wanted to put this out here because this is, you know, sort of -- I think you saw in the aggregate 300-and-some-odd OFOs since 2015, but I think this tells you a little bit more. In 2015, you had three. Okay. In 2018, you had 136. Now if that's one OFO a day, and I may be oversimplifying that, that's a third of the days where this popped up as a problem or it popped up as an issue. Now, you may have had multiple OFOs on any given day, I don't know. I'm not an expert in that area. But the point is there's a significant number of OFOs that are occurring now that historically did not occur, historically, so the system has changed significantly.

As was indicated earlier, the current generation fleet, and this is operating differently than it has historically, but the current generation, electric generator fleet that operates under natural gas, there's basically two types of plants on there. One are generators that have contracts with the IOUs and those are tolled, so the IOUs are responsible for the gas for those power plants. And the others are market generation that basically sells into the ISO market on a daily basis. And there may be days they don't participate, there are other days they do.

Some of the questions that were asked, they do not -- by and large, most of them buy at the citygate for two reasons. One, that's where they are. Two, given the way that they are dispatched and how they participate in the market today as opposed to, perhaps, ten years ago, they do not have any sort of firm transmission rights from the border to the citygate. So they're buying, basically, at the citygate. In a similar venue -- pardon me, a similar view, they are not purchasing -- they are not, basically, hedging and for the same reason. They're basically -- how they operate, when they operate depends on a lot of fairly short-term market issues, so you can be on the wrong side of a hedge. So you're not going to hedge your resources if you don't know with some sense of certainty what that's going to look like.

And so at any rate, so that's basically how that operates. Most of those resources that are popping into the ISO market are going to be sort of bid merit order resources, so they may have -- they may not have the lowest heat rate out there. They're popping into the system as they're needed. They are required, if they're in the market, to operate, so they take that very seriously. They're not allowed to say, well, I didn't, you know, I didn't believe I was going to need that much additional gas so I'm not going to operate. They basically have to buy that gas in the daily market, which I think is, if you looked at Evie's slide, can be a significant challenge.

One of the challenges for the generators in that mix is that if they are outside of 125 percent of the bandwidth that the ISO has utilized to establish what the price of gas is and it's a lagging index, the only way to basically fully recover their gas costs is to file a 205 at FERC, which, to us, does not seem to be a particularly healthy way of dealing with issues. It's time consuming and it's not particularly helpful.

There is a potential for resolving this. And I know that there's an active issue at the ISO which we may hear more about, something called a CCDEBE, which is not a hip-hop artist. It stands for Commitment Cost and Default Energy Bid Enhancements. And what that would basically allow for is for this issue to be more or less resolved, you know, in the ISO markets where these actual gas prices can be transparent and audited.

So the one other thing I want to -- I agreed with a significant amount of what was previously spoken of by other folks with regards to supply. You know, the ISO operates their schedules on least-cost dispatch. And I'm assuming that when they tell plants to operate, that's the least-cost plants that's supposed to be operating.

The first I've heard of hockey-stick bidding was today. I am not sure that's going on at all and we may have to have a discussion on that further because I certainly don't want the dead cat of high prices to land on the porch of the IPP industry. I've been in that movie before, thank you very much, and I don't sense that that's the case. We are basically price takers in terms of generating electricity. And we are hopeful that the supply constraints, based upon the infrastructure in Southern California, are resolved fairly quickly and that those gas prices are stabilized in the long term. Thank you.

MR. BAKER: Thank you.

Rodger, we wanted to bring you back, and we thought it was important to have you on this panel, as well, to hear some responses you might have to what's been said so far.

MR. SCHWECKE: Yeah. And I don't have any additional comments. I think I've probably talked enough already earlier, so I'll wait until the Q and A.

MR. BAKER: Okay. Moving on And I believe to Marlon. Thank you.

MR. SANTA CRUZ: Good morning. My name is Marlon Santa Cruz. I'm the Natural Gas Supply Supervisor for the Los Angeles Department of Water and Power. Good morning, President, Chair and respective Commissioners. I have a couple of brief introductory remarks for LADWP, once we get the slides up. So I'll keep this high level.

We're, essentially, with regards to natural gas supply and daily operations, we are strictly an end user. So being a municipality, our first primary function is, indeed, to meet native load from an electric standpoint for the ratepayer in Los Angeles. As such, we have several responsibilities on our shoulders as balancing authority. That includes maintaining electric system reliability, including the Aliso Canyon withdrawal protocol and the mitigation measures that were published then, along with our responsibilities to NERC, making sure that not only do we meet load, but that we have sufficient reserves in our back pocket to sustain any degree of varying emergencies that could arise on the system.

Additionally, we have our goals toward renewable integration and including, now, renewable energy on the system. So not only are we out there purchasing renewable energy, but we are also doing everything we can to make sure that we regulate it, that we firm and shape it and include it, and bring that to the customers within the L.A. Basin.

As such, as if we didn't have enough on our plate as a balancing authority, we have to regulate the voltage, the frequency, maintain the grid reliability, and that includes not only determining what generating resources we will have on in the basin, but also from our portfolio, what resources outside of our basin, including our transmission lines and so on and so forth. It's basically one giant puzzle every day that our Wholesale Energy Resource Management Team is operating in such they are my client.

I directly support them and their secondary function, also, of then marketing. If they happen to have any excess energy that they can introduce into the electric market, they will do so. And it is my responsibility to support that by bringing enough gas into the system. And also, if they have any energy that they would like to procure from the market and lower their generation, then it is my responsibility, also, to get rid of the gas that we have in excess.

So it's a bit of a balancing act that we perform every day. We operate a little bit differently than the CAISO in that we are a vertically-integrated operator in that we have our own resources and we have our own load and we serve them. However, I'm not here to highlight the differences in our generation between us and the CAISO.

What I would like to highlight is that despite our differences, we are still exposed to the price volatility that happens from the natural gas market at the SoCal citygate. Of course, we do have our own natural gas that we procure outside of the state and we have transportation agreements to bring that into the system.

But with regards to the OFOs, we are still very much on the hook for any noncompliance charges or the penalties, as we've been lovingly referring to, and also the monthly imbalances which we, as I want to echo Mr. Cushnie, sometimes just can't catch up. We behave in a certain way to cushion ourselves to avoid penalties on a daily basis but by the end of the month, we have not had an opportunity to cushion in the other direction. And thus, we are then subject to different penalties. And of course, on a daily basis, whether it be an OFO, a curtailment-watch or actual curtailments, the market reacts.

And our primary responsibility is to perform economic dispatch to provide low-cost reliable energy to the ratepayer. And anything that happens in the market causes our grid operations folks to have to make decisions. Some of them may not be economic, but they have to keep the lights on. And thus, LADWP is still very much exposed in that regard.

So those are my introductory comments. And I should have probably touched base with you at first, Simon. I was assuming that the pre-formed questions, we'll be addressing as we go along or should I address them now?

MR. BAKER: Well, they were to help you

to prepare your opening remarks. If you have anything in addition you want to add now, I think now is a good moment.

MR. SANTA CRUZ: All right. Fair enough. Thank you.

Then I actually just really want to clarify a little bit regarding some of these questions and the way that they were worded. It seems like they were more so from an energy perspective. Specifically, "Why do California natural gas-fired electric generators depend heavily on interruptible service?" It's not necessarily our choice. This is the choice that we have been given.

Essentially, in 2015 when the leak happened at Aliso Canyon, LADWP had some non-firm or interruptible contracts or master service agreements with SoCalGas. We then promptly changed those to firm transportation, but all that was a moot point because when the balancing settlement was agreed upon, effective November 1st, 2016, part of that was that we agreed to the Aliso Canyon withdrawal protocol which was published, I believe, in the first winter technical report, such that we agreed to certain protocols and steps that will be taken before gas can be withdrawn.

But additionally, the differentiation in the subcategories was removed. There's now no longer interruptible or firm transportation services for transmission-local service for non-core customers or, essentially, electric generators. Thus, being a non-core customer, this is the deal we got; we basically are non-core and we will always be secondary to SoCalGas's responsibility to their core customers.

And in responses to why we don't procure more at the border, well, we would love to if there were BTS transmission available; unfortunately, it is not. But even if it were, we are still a non-core customer. When it gets down to the, I'll refer to it as the distribution-level service down within the basin, there is no guarantee that fuel will be delivered to us because, again, we are a non-core customer.

Again, regarding the CAISO and how it operates, I cannot speak for them. They will probably be speaking next as the experts on that matter. We operate differently in that we bring in gas from Wyoming. We have our own pipeline transportation contracts on the Kern River Pipeline and we match it volume per volume on the SoCalGas system and that's it, that's what we got.

If we need any more gas other than that, we have to purchase it at SoCalGas citygate and, thus, we are exposed to those high prices. But that would be a last resort for us because if we have other opportunities to generate from some of our generators outside of California, run hydro, or even buy electricity that would be cheaper than generating it at $39.00 an MMBtu, we would then elect to do that.

And in a nutshell, that is how LADWP generates.

MR. BAKER: Thank you.

Mark?

MR. ROTHLEDER: Thank you very much for the opportunity to discuss this important topic. I'm Mark Rothleder, Vice President of Market Quality and Renewable Integration at the California ISO. I have been involved in this topic since the Aliso Canyon issue first arose and the years following that, that we started to do assessments and tried to come up with mitigation measures.

At that time, initially, the focus was how do we keep the lights on? How do we maintain reliability? The focus was not how do we address some of the potential economic issues that could arise. And so the mitigation measures that were put in place were largely to address those reliability issues.

What we started to experience, as has already been discussed by others, is we started to see last year some more pronounced economic impacts of some of the underlying pipeline constraints and supply constraints in Southern California gas. February of last year during President’s Day, we started to see this. There was a curtailment watch during the cold weather spell and we basically were asked through the protocol during that time whether we could curtail or limit the amount of gas burned on the electric generation?

I should say, we don’t operate any of the electric generation. We only, basically, operate the market and we are a balancing authority area. And in that regard, we do least-cost dispatch to minimize the cost of overall cost to meet electric demand, subject to certain constraints. And some of those constraints are regarding transmission constraints or local constraints that require certain generation in local areas.

And in the particular case in February of last year, that was a case where we needed a certain amount of generation on in the local area to address some of the electric transmission work that was going on. And as a result of that, while we put the constraint on the gas burn, it did cause congestion and higher costs in the local area as a result of trying to manage the gas burn in that way.

I contrast that to the summer of last year where we started to see high prices as a result of gas prices escalating as a result of the OFOs. And during the summer period, we basically have a very high demand in the electricity sector. And as a result of that, gas resources in Southern California are not only needed locally but they actually are needed to meet the system demand. And as a result, you see the correlation between the high gas prices escalating in Southern California and the escalation of the average systemwide prices, not just prices in Southern California but the systemwide processes in the day-ahead market.

And then lastly, in the November time period, we also saw another round of gas spikes but it was, again, during this time period the system loads are lower so the effect was more of a localized impact, although we did see some rise in overall system prices during this time, as well.

So that's the dynamics and the correlation between the gas and electricity market.

In terms of the timing -- oh.

I will say that as the gas prices do increase they do have, especially if it happens after the day-ahead market, they do have the effect of actually reducing the gas burn in Southern California on the gas fleet. Because if you have an escalation of gas prices, you can see here that that shadowy portion below zero is the amount of reduction between real time, in real time, relative to the day-ahead gas burn.

And so the effect of OFOs does have the desired effect of starting to reduce the gas burn, shifting electric supply outside the L.A. Basin to other areas. It may still be more costly, but physically, it's addressing that balancing of gas demand and what we can move in terms of electric supply. We can't always move all the electric supply out of Southern California, and therein lies the challenge.

And therein lies, like in November, we couldn't move -- we were down to, basically, one or two units, non-QF units that are online. When they were -- when we were asked whether we can reduce our gas burn by doing a voluntary curtailment, pursuant to the withdrawal protocol, we looked at it and we said we couldn't, we couldn't shut off any more than the one or two gas resources we had on. And as a result of that we said, no. And subsequently, SoCalGas basically had to withdraw from Aliso Canyon during some of those periods of time.

I won't get into the complications of the timeline except to say, because it's already been discussed before, I will say that this timeline and the misalignment has been discussed several times in the industry. And we've also, in the ISO, has taken up, can we move our timeline around? And the consensus view of all the stakeholders was, no, don't move the timeline around. You start backing it up and you get into bilateral activity and it becomes problematic. So we considered it but we have since -- there is no desire, there's no market desire to move that timeline around.

That said, we have enhanced, as a result of Aliso Canyon, some of the coordination and information that we make available. For example, we now provide a forecast or information two days ahead about the potential gas burn, the expected gas burn of resources in Southern California. We provide that on a total basis to Southern Cal Gas to coordinate with them as a system operator, as a gas operator. We also make the megawatts available on the resources, available to the generators if they want to use that to kind of guide their gas procurement before the actual day-ahead market that starts at 10:00 a.m. So we do that.

But to the extent these OFOs come in after the day-ahead market, the day-ahead market is over, we've already done -- determined the amount of megawatts for the most part. And if they have to then buy gas at that higher price, they're exposed.

There was a reference to the -- we do have market power mitigation in place to protect against exercise of market power. Some of those measures put limits on the amount of costs a resource can receive for commitment cost, startup cost. And if they're, in the case, mitigated, they're default energy bid in the case of mitigation.

These are tied to these indices. And to the extent these indices move from one day to the next or intra-day, there is, what we've seen, is we've seen these situations where the index or our use of the index is not keeping up with that change.

And as a result, at least in the summer, we had the occurrence where even with our mitigation and our caps on our constraints on commitment costs, it was -- the prices that were paid to these resources were insufficient to cover their costs. And as a result, at least three suppliers did avail themselves of the FERC process to recover those unrecovered costs. And they're in the middle of that process today. So that was the first time that was exercised and used to account for that.

I'll just say that we have done a significant amount of increased coordination. We've done month -- seasonal assessments in response to the Aliso Canyon situation. We do daily coordination where we talk about -- we communicate our gas burns, our expected gas burns. And in response, we get information whether there's a potential or risk of gas curtailment and we take that into consideration. And it allows us, if we need, to put some constraints around the day-ahead market run.

Further, in the real time, we continue this coordination all the way down to real time. And if we need to continue to perform any additional constraint management to reduce the gas burn, it gives us the opportunity to do so if we can accommodate that. If we can't accommodate that, we will inform the gas operator that we can't and then have to move on in terms of the protocol.

In terms of solutions, I'll just end my statement with this, that, obviously, if we had the gas infrastructure and the gas pipeline back, that would obviously help. Absent that, I think we do have to look for other measures.

Mr. Cushnie mentioned, is there some way to that mechanism through resource adequacy to require resource adequacy resources to buy firm gas or have a mechanism that there is sufficient gas supply and hedging for those resource adequacy resources? Largely, these are resources that are in the local area anyway. Perhaps that's a mechanism that can be explored.

The third one is perhaps there needs to be a relook or a revisit of the protocol itself. Currently, the withdraw protocol says you do not -- they do not withdraw until the point where they've evaluated and asked whether there was any voluntary curtailment that could be accommodated. That's already largely at a point where they've already exercised their OFOs, Stage 3, Stage 4, and it's already had the effect on the prices.

So perhaps there's a mechanism for consideration and that is, do you back up the protocol to allow for withdrawal, limited withdrawal for the purposes of mitigating or reducing the risk of going into the higher OFO protocol or OFO levels and protecting the

potential economic risk?
So I will stop there and I look forward to the questions.
CHAIR WEISENMILLER: And let's start with a couple, just setting some context.
LADWP, I assume you were asked, also, to curtail. Did you curtail in December? Could you? Could you and did you?
MR. SANTA CRUZ: I have to clarify that I speak for the, I guess what would be considered the marketing and the public side. So I can say that, yes, a public notice went out after the fact. I do not know any of the details that happened between the grid operations folks at LADWP and the operations folks at SoCalGas.
CHAIR WEISENMILLER: I would like you to supplement and file that information of whether you were able --
MR. SANTA CRUZ: Sure.
CHAIR WEISENMILLER: -- LADWP was able to reduce.
MR. PEDERSEN: Chair Weisenmiller, I have that information.
CHAIR WEISENMILLER: Sure.
MR. PEDERSEN: And we did ask, not only

CAISO but LADWP. LADWP was able to move a small amount of gas in all three days that we were looking at, except for July 4th.

CHAIR WEISENMILLER: Okay.

MR. PEDERSEN: The numbers for July 3rd was about 19 million cubic feet, about 38 million cubic feet for January 7th, excuse me, January.

CHAIR WEISENMILLER: In January.

MR. PEDERSEN: So they were actually able to move some supply. Where they went, I don't know, but they were able to reduce their demands.

CHAIR WEISENMILLER: That's good. I was just trying to figure out, obviously, the ISO wasn't able to, whether or not anyone else was able to. I suspect neither were burning much gas so that there wasn't a big impact. But it would be good for the record, just to get that.

Also, Rodger, you had --

UNIDENTIFIED MALE: Chair Weisenmiller --

CHAIR WEISENMILLER: Go ahead.

UNIDENTIFIED MALE: -- we do have John Giese from LADWP who can answer your questions, I believe.

CHAIR WEISENMILLER: Please come up to the microphone and introduce yourself.

MR. GIESE: Chairman and Commissioners, my name is John Giese.

CHAIR WEISENMILLER: Push the green button.

MR. GIESE: How's that?

CHAIR WEISENMILLER: Better.

MR. GIESE: Good morning, Chairman and Commissioners. My name is John Giese. I work in the Wholesale Energy Resource Management section at L.A. Water and Power. And when the voluntary curtailments come through, I'm in the organization that actually works to comply with them.

Recently, we've had some voluntary curtailments in the last couple of weeks. And I would say in the last couple of weeks a typical burn that we were working with before the voluntary curtailment is asked for is somewhere in the 80,000 MMBtu per day range. We are typically able to cut anywhere from 20,000 to 30,000 from that.

Also, currently, when we believe that voluntary curtailments might continue, it would be common for us to go and make a purchase to proactively remove a little bit of gas from the system in a period of time where we believe that the curtailments might happen. And we actually have a purchase like that going right now which has removed probably about 5,000 to 8,000 MMBtu of our burn per day from the system because we weren't sure if a voluntary curtailment would be called and we wanted to make sure that we were doing something to address it proactively.

CHAIR WEISENMILLER: Thank you. Actually, I'm going to ask Mark a similar question, then ask a general question. I'm not quite sure which of you could respond, so it may be easier if you just stay standing.

MR. GIESE: Sure.

CHAIR WEISENMILLER: So, Mark, what were the comparable figures for the ISO in terms of throughput?

MR. ROTHLEDER: I don't have the exact figure. I can give them to you after I --

CHAIR WEISENMILLER: That's fine.

MR. ROTHLEDER: Yeah.

CHAIR WEISENMILLER: And just submit it later.

MR. ROTHLEDER: Yeah. I will say that we do have the incentive, an incentive, to comply with a voluntary curtailment, especially if there is a risk of an involuntary curtailment coming because an involuntary curtailment is even less in our control in terms of what resources are curtailed. And so we would much rather manage this and avoid an involuntary curtailment if we can. And so we have the incentive, if we can, to accommodate that.

CHAIR WEISENMILLER: Okay. Obviously, one of the things that's gotten people's attention is the billion-dollar number. And so just starting out, first, the proverbial question of how well did -- you know, obviously, LADWP doesn't have an ERRA account, but how well did you do on forecasting gas procurement costs this year? Do you know how much larger they were this year?

MR. GIESE: I think I'd have to defer on that because I typically think of how much we use, not what we pay for it.

CHAIR WEISENMILLER: Okay.

MR. SANTA CRUZ: Sorry. If I could just clarify the question? Are you asking how much additionally we had to purchase natural gas from a dollar standpoint?

CHAIR WEISENMILLER: Yeah.

MR. SANTA CRUZ: I night actually have that. Well, all I can say is that we are keeping costs month to month. And in 2018, it was to the tune of, I believe, several hundred thousand dollars. I would have to get back to you with the actual figure.

CHAIR WEISENMILLER: And, SDG&E, do you have a sense of what your power filing is or will look like?

MR. HELM: Sure. So I think with the ERRA filing and what we looked at over the summer, we did, in fact, face higher SoCalGas citygate prices -- or citygate prices that we had forecasted, and so that was certainly something that impacted our ERRA forecast.

Overall, there were a host of factors, however, that effected our ERRA so that we sort of quickly self-corrected and we do not expect -- we did not trigger in 2018. And a number of those factors include we did accelerate some of our forward buying of gas prior to the summer and I think realized a benefit of that relative to what we normally do. We normally buy most of our gas forward a month ahead and we accelerated that a couple of months.

But in addition to that and some of, I think, the larger impacts on our ERRA were a result of the fact that renewable generation during the time period was lower than we had forecasted, and so that reduced our renewable related costs. We had higher revenues from the market for our gas generation. And then we also had the high usage charge over the summer. And so while we're not in a situation where we triggered in 2018, I think when you look at all of those factors together, I can't guarantee that that would be the same going forward.

CHAIR WEISENMILLER: Yeah. I think it would be useful for us just to know across all of you what the impact of the congestion has been --

MR. SANTA CRUZ: If I may?

CHAIR WEISENMILLER: -- you know?

MR. SANTA CRUZ: I just actually found I had the chart with me.

CHAIR WEISENMILLER: Okay.

MR. SANTA CRUZ: We compiled from January to November of 2018 alone. The losses from natural gas procurement standpoint alone, because we have two different accounts, the Energy is keeping their bank account, not including December because we haven't received our invoice yet, we have already exceeded $2 million.

CHAIR WEISENMILLER: So again, if, Simon, if you can just reach out afterward and so we get a sense of what, comprehensively, things look like.

Yeah, Colin?

MR. BAKER: May we hear from Colin?

CHAIR WEISENMILLER: Yeah.

MR. CUSHNIE: Yeah. I think this has been a really good conversation to kind of highlight what at least the challenge has been on the Southern California Edison system.

Our ERRA under-collection is almost entirely the result of higher power prices, not gas prices.

CHAIR WEISENMILLER: Um-hmm.

MR. CUSHNIE: I made a comment in my opening remarks that it's very small packages of gas that are being priced at these, you know, these higher penalty prices or high prices on the margin as generators are trying to get into balance. But that single package of gas can then set the power prices for the entire grid. And so it really depends on what is your physical position as a utility?

So DWP, I'm assuming, based on my knowledge, is largely a resource so they're physically self-hedged. I think San Diego Gas and Electric has a much larger physical position relative to their load than Edison does. Edison only owns about 20 percent of the generation that's used on our system. And then we have a small amount of tolls that we do, as well. Our hedging activity, we do hedge natural gas prices. But natural gas prices are at Lakewood at the Southern California border and have been for many, many years, and so that's where the hedges occur.

We're not seeing a lot of volatility at the SoCal border, we're seeing volatility at the SoCal citygate. And it is very difficult to hedge at the citygate because you have a constrained system and you need to have folks on the other side of that transaction that are willing to take the risk of what the citygate price is going to be to sell you a hedge. So we're just positioned differently than all other entities here that I think you're asking about.

We can also -- you know, we're happy to work with you and CPUC staff to talk about how our procurement plan construct works and the T-Board construct that the CPUC asked us to use. It doesn't look at constrained pipeline capacity risk. It looks at macroeconomic risk and that's what we're being asked to hedge to.

CHAIR WEISENMILLER: Okay. And how -- of your total costs, what's been the economic impacts of the OFOs for the monthly imbalance charges?

MR. CUSHNIE: Yeah. So I'll -- we can break it out. Our total gas, actual direct gas-related impacts from the OFOs and so forth is very, very modest. And it's the power price impact from that that is driving our costs.

And just if I may for Mr. Smutny-Jones benefit, if I wasn't articulate, I apologize. What I was trying to communicate is that generators, when they buy their gas and they pay whatever the price is for gas, they may be paying $4.00 or $5.00. But if they are faced for penalty gas that they haven't procured, their bid curve, presumably, will then put the penalty price in. And so it makes it look like the hockey-stick bidding that we saw before. I wasn't suggesting that people were exercising market power, it's just that you have two states of gas and you have to price, you know, your volume risk based on penalty prices.

MR. SMUTNY-JONES: Yeah. It's my understanding that once an OFO is declared the people who sell gas, basically, bake that into the price. So it's not so much the generator, that's what you're going to pay, at least that's what I've been told by the generators.

CHAIR WEISENMILLER: And so back, same question to LADWP and SDG&E in terms of the impact on your procurement cost of either OFOs, direct costs, OFOs or the monthly?

MR. SANTA CRUZ: If I may put into context? Los Angeles, for the most part, we have, again, our pipeline transportation that covers our needs for the majority of the year. It is particularly in Q3, July through September, that we see our high loads and then we are susceptible. But the OFOs, we face throughout the year --

CHAIR WEISENMILLER: Right.

MR. SANTA CRUZ: -- of course, throughout the entire system. So our financial services organization did actually run a model as to one specific event, which was the summer on July 23rd, and what that impacted our ratepayer. And it turns out that it affected our rate by about two percent. So it seems small, but that was just one instance and they're still running their tabulated calculation for the entire year, whether or not that's going to have an overall impact for the next year when we request our rate to stay or not.

MR. GIESE: And on a daily basis, that one percent is pretty common on the electricity dispatch side, as well. So if we do uneconomic dispatch, it's usually about a one to two percent hit, sometimes a little bit more.

MS. HELM: For us at SDG&E, we'll follow up with you, Simon, with actual numbers. But for SDG&E, it's very similar to the case of Edison. We don't -- we didn't incur a lot of penalty cost. Instead, we went out and bought the gas that we needed to buy. And so the cost impact really came through the price of -- the market price of gas and then how that translated into the market price of power, so --

CHAIR WEISENMILLER: Yeah. I was going to ask, Colin, on your solutions slide, can we just put that back up for a second?

COMMISSIONER GUZMAN ACEVES: Mr. Chairman, while you're pulling that up, can I ask a follow-up question of Kendall?

Can you describe again how you shifted in increasing more forward procurement and what, like what exactly that looked like in a little more detail?

MS. HELM: Sure. So our purchasing of gas forward, the physical gas that we purchase, is typically done a month ahead within the limits of our BPP, our Bundled Procurement Plan, that governs how much of that we can do and how quickly we can do it. We did, prior to the summer, accelerate some of that purchasing of forward gas that either are fixed or index-based price, a little bit sooner than a month ahead, maybe to a couple of months ahead. And I would say that looking back, that was a decision that did provide benefits for us.

But I think, you know, we can talk about hedging strategies, that's a form of hedging your price exposure. Hedging strategies are certainly something that, you know, if you had perfect information and always knew how to hedge, there wouldn't be a market for it. Hedging works for you sometimes, it doesn't work for you other times. It's a way to limit volatility and your exposure to price changes. But it's very difficult to predict where prices will be, so it's not a strategy that's cost free. There's benefits and costs to hedging.

CHAIR WEISENMILLER: Yeah. So what I --

COMMISSIONER RANDOLPH: Chair Weisenmiller, could I ask, before we move on to the solutions question, I kind of wanted to follow -- ask a last question about quantification --

CHAIR WEISENMILLER: Okay.

COMMISSIONER RANDOLPH: -- which is I think both Colin and Marlon mentioned procuring power from outside of the basin. Is that sort of a strategy you used to kind of reduce the price impact? And did that have more -- did that result in more reliance on out-of-state coal generation or any other potential impacts?

MR. CUSHNIE: Commissioner Randolph, so

Edison does procure a fair amount of energy from outside of Southern California. We import energy. A lot of that is actually tied to our resource adequacy obligations. It's procured almost entirely as system energy. And so whichever control area it's coming from that, you know, that -- you know, the supply mix in that control area is dictating what the, we'll call it the incremental carbon emissions are will be assessed the system average, but we're not able to track what the marginal carbon impact is from that.

Yeah, the firm energy imports provide price stability, to Kendall's point. And I would also note, Commissioner Guzman Aceves, I mean, Edison also does hedge natural gas. But again Edison, you know, controls maybe ten percent of the gas that its system needs on a peak day. And so it's not the gas costs that we're incurring for our native load, it's the gas cost that other generators are incurring that are driving up our power prices and impact our customers' costs.

But, yeah, we do try to bring in firm energy, but there's going to be a limit as to how much you can do because then, you know, the ties start to become constrained. And then the liquidity in the marketplace starts to thin out pretty fast as you start to move up the stacks of other control areas resources.

MR. SANTA CRUZ: I'd like to qualify before I quantify in that DWP, again, we have our portfolio. And of course, we are primarily trying to keep the cost of the energy low, so the lowest cost resources get dispatched first.

Now in the event of a high price spikes, as just what happened at citygate, and in the event that we are caught in that, that we need to find ourselves purchasing more gas than what we can bring in from out of state, our economic dispatch dictates that we go to the next lowest cost resource, so if that resource is something cheaper. We have natural gas-fired generation outside out of the state, we do have some coal-fired generation, depending on the price basis that happens on any given day, it may get ramped up to support the load. And also, we might even find ourselves running some of our hydro in the event of an emergency, that we need to ramp up suddenly, those resources can't bring in the energy that we need.

So we have a potpourri of options ahead of us. It's not necessarily that we look to the market to purchase energy as a strategy, it's just another tool that we have in our bag.

COMMISSIONER RANDOLPH: Thank you.

CHAIR WEISENMILLER: Okay. So again, what I was trying to understand was looking at Colin's list, at least two things flagged, were the OFO and the monthly balance issue. So on the one hand, we heard from Rodger earlier that an OFO results in some increase in supply. And I assume part of what you're trying to do is sort of dampen demand. But again, as you look at, at least, these options it comes to trying to understand what the cost impact has been on the power prices and what the resource benefits have been on the gas operations.

So at least at this point, Rodger, do you have a sense of how much the power sector -- how is the power sector responding to either the OFOs or the monthly penalties in terms of benefits for you operationally?

MR. SCHWECKE: Yeah. Chairman, I think we -- what I have is how the whole system, okay, and whether it's a particular sector is increasing deliveries, but I think we had -- I had one slide and it shows -- and we do see a swing up in deliveries, all the way up to, you know, potentially 300,000, 400,000 decatherms, that supply into the system is increasing. It's having that effect. I can't say whether it's electric generators. I can't say whether it's refineries or whoever it might be. You know, there's probably information that if we wanted to get down to and dig a little deeper into that data, we could probably come up with that information and look specifically, who was short and who then reacted.

CHAIR WEISENMILLER: Yeah. Well, back on, Colin, you had made the recommendation. But again, have you been able to get any additional supply? I mean how, generically, how do you respond? I mean, what's the benefit operationally relative to the cost to you?

MR. CUSHNIE: Yeah. So, you know, that's the Moneyball question. So when the OFO was called the OFO was called in the afternoon to early evening for the following operating day. But at least in the case of CAISO interconnected electric generators, we've already purchased our natural gas from the market. We've received our awards back from the CAISO and, therefore, there may be a mismatch between our generation awards and our flowing gas supplies.

But when the OFO comes out we will, if we are long or short on the wrong side of the OFO, we will engage with the marketplace and effectively pay prices up to the penalties that we would otherwise inure to our imbalance to close that physical shortfall.

Now I think, you know, something that's helpful for some folks to remember about the gas system is, you know, the gas flows very slowly by electric standards, right, you know, 30 miles an hour or so. So when we're trying to buy gas at eight o'clock at night, there's not -- you know, we're not able to access, you know, the Texas basins or the Canadian basins to move gas. You're really, what you're doing is you're moving gas around in the western United States at that point in time and having somebody take a little bit less upstream and maybe move that incremental gas into California.

So we think the OFOs are helpful, so Edison is not suggesting to not have OFOs. What we're saying is that, you know, the penalty prices associated with the OFOs are not making any sort of a meaningful difference to the reliability of the physical gas supplies flowing. When the Gas Company calls an OFO, it doesn't matter whether it's $1.00 or $5.00 per million BTU, Edison is still going to take whatever actions it needs to try to get it into balance because we don't want to incur that extra $1.00 or $5.00 penalty. Charging $25.00, all it does is we just, we'll pay up to $25.00, but it doesn't change the amount of gas that's available to us to procure.

And so it seems like it's just amplifying, to a great extent, in an unnecessary way the high power prices that all customers have to pay.

MR. BAKER: Mr. Smutny-Jones, I see you might want to jump in here.

MR. SMUTNY-JONES: Yeah. I would just caution on this. My understanding of it, there are five stages. And the stages are designed to basically, you know, you ramp up to the higher price. I think that when you're trying to change behavior at lower prices, the imbalance tolerances are reduced in each of those stages.

So I think the point is you're trying to get behavior changed in each one of those stages and go and just do, it's either zero or $5.00 or zero, pick a number. There is some concern about the efficacy of that, if that's really the best way to go. So I think that that would warrant, perhaps, a little further discussion as to whether or not that's --

CHAIR WEISENMILLER: Well, I was going to ask --

MR. SMUTNY-JONES: -- (indiscernible).

CHAIR WEISENMILLER: -- in terms of LADWP, in terms of your behavior, or SDG&E's, how does the $25.00 effect you on a Stage 4?

MR. SANTA CRUZ: Well, again, when it comes to a Stage 3 or Stage 4, I can only comment on what we've observed.

CHAIR WEISENMILLER: Right.

MR. SANTA CRUZ: And I'm going to second what Jan Smutny-Jones has said, is that it appears that if marketers are concerned that they're going to be hit with a potential penalty, they roll that into the price of the commodity. And DWP has been exposed to that, namely in Q3 when we had to procure at the SoCal citygate. It hurts us because, of course, the generation is going to suffer. It doesn't hit us as hard as it might hit some of my fellow utilities here in the room because, again, we have these other options in our tool bag that we can shift generation outside of California. But there are some instances when we've noticed that, indeed, it does affect the price.

Now I'll just defer a little bit of opinion that if the penalty regarding traveling ten miles an hour above the speed limit versus 100 miles an hour is the same, I would have gladly driven here from Los Angeles this morning, but that's not the case.

And so I understand what SoCalGas is doing, that it's a tool meant to incentivize end users to meet their load because they're trying to protect system reliability. And I guess that's all I'll comment on that.

For the pricing structure, it is what it is.

MR. GIESE: I could maybe add one thing to do that. When we're on the floor trying to meet our load, the reliability of meeting our load is really our core issue. When the gas supply gets threatened the reliability of meeting our load is threatened, so we're going to take a lot of actions to make sure that that gas supply is reliable and that we don't end up with a bigger problem than we would have.

So the size of the penalty, yes, it does get our attention and it affects our economics. But a lot of our behavior is designed to support that gas system no matter what because the RMR generation that we have to run that is going to rely on the gas that's in that system, if that RMR goes away we have a much bigger problem than an OFO penalty.

MS. HELM: Certainly. And I would just add that when there is an OFO and we see that there is an imbalance, we certainly try to avoid the penalty. And so we'll, if we have a short position, we'll go buy gas to eliminate that imbalance. And during those situations, we are price takers, so we will pay the higher prices and, usually, the penalty price is priced in and so we do see higher power prices.

I think in general, though, this goes back to one of the points that I made earlier in terms of as an individual market participant, I really don't have the visibility to determine what is the magic price that's going to be effective at incentivizing behavioral change without penalizing parties that don't have the ability to fully respond to that market incentive. There's a lot of complexity about what that price level would be, as well as how you would want to apply those penalties to different market participants. And it may be such that some differentiation in how that applies is warranted economically.

But again, I think this is where we get into complexities around market solutions and some of the intended and unintended consequences and why I think it does warrant more analysis, but certainly before we go into these complex solutions, revisiting the simple solution to see where we can address some of the structural constraints is important. I think some of the charts that have been shown today have shown that before we hit some of those tipping points, the OFOs that were issued didn't have the same kind of market price impacts.

CHAIR WEISENMILLER: Yeah. I think --

MR. SCHWECKE: One thing --

CHAIR WEISENMILLER: Go ahead.

MR. SCHWECKE: I'd like to add one thing. We talked a lot about the stages and the prices of those stages. Those are all set after the price for the next day has been set in the marketplace. And we're basing what that number is, whether it's the $5.00 or the $25.00, based on what the gas price expectation has already been set by the marketplace. And if you start looking at how you change things and change that price, Colin mentioned Stage 4 and 5, but there's still the ultimate which were, you know, to try do as our emergency OFO. Will we get there sooner? And will that set a different marketplace expectation of what customers (indiscernible)? That's a higher than $25.00 price.

So we have to be cautious going in that we are not making a change that actually will have a negative result.

CHAIR WEISENMILLER: I guess the last thing I wanted to explore was, you know, Mark had shown a chart on the timelines and the misalignment there and indicated last time it was looked at everyone was like, god, don't get into that.

I guess looking at where we are now as opposed to where we were then, is that still the feeling of not adjusting the various timelines?

I'm looking particularly at Colin. If you, you know, knew then what you now, are going through, would you have the same position on don't touch that dial?

MR. CUSHNIE: It's an incredibly complicated consideration because it's just which side are you going to move the problem to? So today the problem is we buy our gas on a constrained gas system before we know what the electric demands are. If we were scheduling the power before we knew -- before we had to buy the gas in a constrained gas system, we'd be projecting what the gas costs are. We would be putting our schedules in. We would get our rewards back from the CAISO. And then we would seek to go match those gas supplies with our -- with the gas demand that results from our generation schedules. But then there would be an economic disconnect potentially for generators, that did they bid appropriately in the CAISO market for gas?

So I don't know that either one is a better outcome. The reason that we ultimately supported the current framework is that the gas market is a national market. And so to, you know, to expect the rest of the country to change the way they were going to -- you know, the hours that they would work and so forth, it didn't make a lot of sense. And asking the CAISO to move its market forward 12 hours would impact the bilateral markets, as Mark mentioned. It would also put more uncertainty between the day-ahead awards and actual market operations because now you have a larger expanse of time that you're covering before you get to actual operations. And a lot can happen on electric grid in the interim.

So, I think, you know, the reason we pointed out these timing disconnects is to highlight that it's not that generators aren't willing to buy the gas that they're required to flow; they just don't know what it is until after they've done their purchases. And when we get into the intra-day gas procurement, and, you know, I won't take up everyone's time, maybe we'll have a sidebar conversation with my colleagues here. There really, there's not, if you look -- you know, if the receipt points are full, there is no more gas to buy intra-day, so it doesn't matter what price you charge. It's just going to -- all it does is impact power prices.

What you're doing now is on -- you know, what you're having is a shipper is willing to change that economic risk amongst themselves. So you might have refineries willing to back down a little bit because they can get a lot more money for their gas by selling it to a generator. But there's no meaningful supply on the system for us to procure, regardless of the price we're willing to pay.

MR. SMUTNY-JONES: Yeah. The only thing I can add there is I'm not sure, you know, if realigning all this makes sense or not, for some of the reasons that Colin indicated.

Again, from the standpoint of the generators that are bidding into the system, you can find yourself in the daily market spending a lot more on gas operating under dispatch orders that are there to keep the lights on, you're buying the gas. And if it's out of a certain bandwidth, your only alternative is to file the 205 at FERC which is very expensive and time consuming. This has happened. This hasn't been a real current experience but it's happened. It has happened. And the concern, of course, is if that starts becoming more common. Then you have less people, potentially, willing to participate in a market where, you know, the only way they can recover the costs that they spend in terms of meeting the dispatch order to keep the lights on is to spend a lot of money going to FERC to recover, you know, their costs.

And so we think that that's resolvable her in California. And I know there's been discussions going on at the ISO to resolve that. And that would -- hopefully, we'd be able to see that sometime this year. But that's the key problem there.

MR. BAKER: Mr. Santa Cruz, did you want to give a brief remark?

MR. SANTA CRUZ: Yeah. I just actually want to take a segue from Mr. Cushnie and Ms. Helm in that, again, forgive me for being longwinded but I didn't get a chance to offer my potential solutions, in that the structure of the OFO has its place. And I think we're all in agreement that this incentivized tool is there for a reason. I just want to comment and highlight that it loses its effectiveness when not all of the participants are obligated to meet it.

And what I'm trying to highlight here is that the Gas Acquisition Department at SoCalGas, particularly, balances to a forecast and not to a burn.

What that means is that, for example, in the event of a low OFO, when the participants are concerned about potentially being faced with a penalty will, on the day of, purchase more gas if we see that our burns are going to increase. And we might even pad ourselves a little bit by buying some extra, again, to avoid the penalties, everyone except the Gas Acquisition Department which balances to the forecast which, even if their burn ran away from their forecast, they are kept whole; they are not facing any penalties because they matched their forecast. And what happened to all the padding that everyone else brought into the system? Well, they appear to be the direct beneficiary of all that padding.

Again, I'm really painting this in the extreme case. But I just want to highlight that that is what's effecting the OFO structure itself. It's not as effective as it could be.

MR. SCHWECKE: So you know, I know there's someone from our Gas Acquisition here, but I want to kind of comment on that.

You know, if we're looking at prices and we're concerned about supply and demand, I don't agree with the assumption that that is driving OFOs with regards to the core balancing to the forecast because that forecast, as we know, all forecasts are wrong. They're either high or they're low. And also, core does have, as Colin mentioned, have access to storage that they would just balance the storage. But if they had to go out and buy supplies, that would actually drive the price up. There would be another participant in the marketplace trying to buy gas in a short situation, which could have a negative impact.

I think Colin's point about not having resources available, historically, that's what natural gas storage has been available for customers to do. I need gas today. Where can I get it today? There is gas that's already in the basin.

So I'll stop there and allow other comments.

MR. CUSHNIE: And so this is a very complicated issue. And you know, I already made a point on it earlier. I had one thing I wanted to make sure all the Commissioners understood about Edison's ERRA balancing account.

So we have done our year-end closing and our under collection is now at 833 million, so it's less than what we had projected in our filing. That's partly a function of prices in December came off quite a bit in the latter half of the month. But some of the hedges that we had put in place earlier in the year were in the money and so some other offsetting factors. So we're under collected by 833 million, not the 900-plus million that we were projecting. So that's ultimately what we would want to be able to put into rates at the end of the day and recover from customers.

But the point is that's just a lot of money. That makes -- that causes rates to go up over one cent a kilowatt hour. And there's a tremendous amount of energy being spent at the Commission, within my company certainly, to try to keep rates as low as possible and that one cent overwhelms everything that we do.

COMMISSIONER GUZMAN ACEVES: I just wanted to go back to a couple of your other suggestions. One was the immediate PFM. Did you say you filed that jointly with SoCalGas?

MR. CUSHNIE: I would have liked to. I couldn't get them there. SCGC; the folks to your left and my right.

COMMISSIONER GUZMAN ACEVES: Okay. And does that include this additional fix that Mr. Santa Cruz suggested on the participation of the SoCalGas purchasing authority? I'm probably getting that name wrong.

MR. SANTA CRUZ: Southern California Generation Coalition. Actually, to speak to that effect, can I ask Norm to answer that question? This is Norman Pedersen with the Southern California Generation Coalition, he represents that. And I'm not sure if what she's asking is exactly in that same --

MR. PEDERSEN: No, I didn't catch it was exactly the same.

Would you restate your question which was directed, I thought, to Rodger Schwecke?

COMMISSIONER GUZMAN ACEVES: No. Initially it was a little -- a question to Colin. But I think my question is actually for the suggestion you were just making regarding the additional fix, not just on fixing the price increase on the OFO penalty.

MR. SANTA CRUZ: The balancing to the burn instead of fix?

COMMISSIONER GUZMAN ACEVES: Yeah.

MR. PEDERSEN: That's an entirely separate issue. It is in the proceeding. It's an issue in a proceeding that's currently pending before the Commission. The docket number is A1710002. The opening briefs are due on next Wednesday, the 16th.

And the position that we have taken, as Marlon explained quite straightforwardly, is that the Gas Acquisition Department should, like all other customers on the SoCalGas system, or non-core customers at least, they should balance to their actual daily burn which can now be determined through the Automated Metering Infrastructure system that SoCalGas has put in place at a cost of over $1 billion. We ought to be getting more for our billion dollars than just getting rid of a lot of meter readers. And what we ought to be getting is the Gas Acquisition Department doing just exactly what the non-core customers do, and that is balance their actuals.

And actually, in the testimony that has been filed in the proceeding jointly with SCGC and The Indicated Shippers, we have data that shows, and this will be in our brief, we have data that shows that the Gas Acquisition Department avoids noncompliance charges by balancing to a forecast.

But when you take into account the error in the forecast, for a substantial number of days when OFOs are declared they are actually putting the entire system out of balance. And the overage that Marlon was talking about, that Mr. Santa Cruz was talking about, when non-core customers overreact to say a low OFO declaration and buy even more gas than they need, they err on the far side, they go high, okay, instead of being low. The Gas Acquisition Department not only just gets up within the five percent negative imbalance tolerance, but because of the error in the forecast, they're way below what they would have needed to bring into the system to be in balance. And as a result, the entire system is out of balance and the differential can't be made up by the overage that occurs because of the non-core customers overshooting the mark.

COMMISSIONER GUZMAN ACEVES: Okay. Thank you.

And I just wanted to also get another one of Colin's suggestions, the slide is not back up, but his longer-term suggestion and get some feedback from some of the others here on that suggestion. And this was, again, to implement a gas supply procurement tariff.

MR. SCHWECKE: Commissioner, I'll go ahead and jump in. You know, very interesting proposal. It takes us back to the 1980s in which SoCalGas used to buy all the gas for all the generators until it was unbundled and that non-core customers started buying their own supplies. I think it's something that has to be, obviously, looked at, can be looked at. We'll have to look at what requirements there are because now you'll be putting the requirement -- their concerned about gas acquisition group balancing to a core forecast, this will -- is a magnitude of ten. And then also, is there any cost subsidy that would occur by doing this between -- to non-core customers to core customers?

Gas acquisition, and they can talk more about it, their mission is to buy gas at the lowest price possible for their core customers. Adding this in, what will it do? Obviously, something that could be explored.

CHAIR WEISENMILLER: I was actually going to ask in -- well, Heather, tell people when comments are -- written comments are due. But I would assume they're going to ask for any and all suggestions, but part of it would be, certainly, reacting to this list in your written comments. And again, certainly happy to have other ideas thrown in. But let's at least make sure that we get some thorough vetting. I don't know if anyone else has got --

MS. RAITT: Written --

CHAIR WEISENMILLER: -- specific recommendations. But again, in getting comments on this, any and all specific recommendations would be useful.

MR. SMUTNY-JONES: Can I ask just a quick question? Sorry, Mr. Chairman.

Who is actually procuring this gas?

CHAIR WEISENMILLER: Go ahead.

MR. CUSHNIE: So the proposal is that the Gas Company would procure this gas under -- with CPUC oversight. It would be a cost-of-service-based tariff. There's a lot of different ways it could be structured but, you know, conceptually, you would probably want it to be a daily reset based on actual costs. And there would be a balancing account so if they over collected one day, they'd refund down the road. If they under collect, they have to recover more. But they would be able to publish a tariff price for the commodity that would be available to electric generators. And then you would look to the munis and the CAISO to give forecast of what the next day's gas demand is so that the Gas Company could procure to those gas demands.

You know, I mentioned in our comments, each of us as individual generators have a lot of variability in our gas burns on a day-to-day basis. But the CAISO's system in aggregate has a lot less variability, so the CAISO can forecast with much greater certainty what the total gas demand is, and therefore it will reduce the operating pressure that the Gas Company is currently having to manage with electric generators swinging high or low on their system.

MR. SMUTNY-JONES: Mr. Chairman, we'll be happy to look at this. I'm just cautious about going back to a system that we deliberately left for some good reasons.

CHAIR WEISENMILLER: Back to the future. Yeah.

COMMISSIONER GUZMAN ACEVES: Mr. Smutny, are you saying you don't like the central buyer?

MR. SMUTNY-JONES: I don't want to wander in -- I don't want to wander into other subject matters. But, you know, I do think we've moved in the direction we're in today. It seems to me that based on what I heard today the primary problem is the infrastructure that's used to deliver gas has some fundamental problems to it. That's not only just Aliso Canyon, which we might want to look at is, is there any more flexibility? I know that's a third rail and I don't want to go necessarily down that road. But is there more flexibility out of that? And can we get the rest of the pipelines fixed?

And I recognize the big elephant in the room is we have a state that's making commitments that we're going to get off fossil fuels, so how much money do we -- are we supposed to spend on the existing infrastructure? I think the existing infrastructure is going to be with us for a while. That gas leak needs to be there to keep the lights on. And it is less utilized today than it was ten years ago but it still -- we still have nighttime here and we still utilize those power plants to meet some pretty incredible, you know, ramps.

So the question from my perspective is what's it going to take to fix the pipes? What's going to fix -- what's it going to take to fix the storage and recognize the fact that we're basically going to be maintaining this system for a bright and beautiful tomorrow where you can, you know, take hovercraft and tunnels underneath Los Angeles, and it's going to be a much different world.

But I think for the meantime, we have to maintain what we have. It was working okay. This is kind of a new problem here. And before we start going back to where we were, you know, 20 years ago, maybe we ought to look at what we can do with the existing infrastructure to make sure that these cost issues, which sound to me that's everyone is in agreement, this is a supply and demand problem, get fixed.

CHAIR WEISENMILLER: Yeah. Okay. So we're going to take a break. Be back here by, I was going to say quarter to.

MS. RAITT: Okay.

CHAIR WEISENMILLER: Yeah. So we'll split. We're, you know, we're running a little bit late.

(Off the record at 1:03 p.m.)

(On the record at 1:48 p.m.)

MS. RAITT: So we can go ahead and get started back with the workshop on Southern California Natural Gas Prices.

And so our third and last panel for today is on Natural Gas Price Impacts on Core and Non-Core and Non-Electric Generation Users. And the Moderator is Jean Spencer from the CPUC.

So thank you, Jean.

MS. SPENCER: Good afternoon and welcome back. So this panel will be focusing on -- we've heard already -- closer.

So earlier today, we heard about getting gas onto the system, and we've heard from the non-core electric generators. So this panel will give a chance for other market participants to let us know their views, including non-core/non-electric generators, and the core customers of the Gas Acquisition Department which purchases gas for the core customers at SoCalGas.

So I'll let you all introduce yourselves as you begin your presentation, but we'll start with Evelyn 'Evie' Kahl.

MS. KAHL: Good afternoon and thank you again for the opportunity to talk about this issue.

I wanted to start with an observation of what's gone right from the perspective of customers. And two things happened a few years ago that prepared, to some degree, for this set of circumstances.

One was we worked hard on curtailment priorities to figure out who to protect, how much to protect, and what the curtailment order would be in the event of an actual need for a curtailment. The other thing we did was to work on balancing rules which led to the OFO rules and which have really helped, I think, keep the system in balance. So those things have gone right. And it's really important to us that those continue to stay on the books.

When I look at the EPUC cost impacts, and again, I probably can't talk about those in detail, but they came in three flavors. They came as increases in electricity prices that they purchased from Edison, increases in gas costs and that was basically the co-gen gas or the operational gas, and then the OFO penalties or noncompliance charges. So they have been affected in many ways by what has been going on in the last few months and they've handled it differently. They're all differently situated, so some have handled it better than others.

And just to give you a sense of the hurt with respect to the SCE under collection, my group alone will bear 10 to 15 percent of that over the next year, so it's a big hit for this industry.

But the thing I did want to touch on was the core balancing issue, just briefly again. I know we talked about it this morning.

And I don't have the advancer.

So as was explained this morning, non-core balances to actual core does not, or balances to forecast. And so the consequences for that are when the core is out of balance what can happen is they can actually cause an OFO. They can increase the penalties for an OFO and just generally have an effect on all other non-core customers. And they don't affect the core, really, because they don't really pay the noncompliance charge because they're balancing the forecast. So again, what the core does deeply affects the non-core costs.

And I pulled out of the Commission's report Figure 8-A there. And it was just a snapshot of how the core did in its forecasting during the period of February to March of 2018, and so it's basically 30 datapoints. And the report noted that there was some problem with forecasting, but I think it understates the problem with forecasting.

If you look at that particular slide and you look at how much is below the line, which was the amount that's really impacting the low deliveries, it's pretty significant and it's pretty regular; it's about two-thirds of the time. And so sometimes that might be, you know, a couple percent, sometimes it might be more, but it's a very important amount.

And as Norman Pedersen was mentioning earlier, Cathy Yap did some analysis of the core balancing in the case before the PUC and she found that in 2016 and '17, they were exceeding their tolerance by 103 percent on average, and for 2017 to 2018, they exceeded their tolerance 62 percent on average.

So to us this is a really, really important matter that needs to be fixed. It's something we've known about, again, for years. You know, like the lines, these are not new issues. We've been talking about this for a long time. And so it's really critical to us that this gets done and this gets done quickly at the PUC so that core has the right incentives to start balancing.

So I won't go on, on the maintenance issues since I've already touched on those. But again, I think that's our key message, is it's the maintenance. And there are many other things that we need to do to prepare the system for all kinds of events. But if we get the maintenance solved and get it solved soon, it's going to provide a relief to the increased costs and operational effects we've been experiencing.

So thank you.

MS. KAHL: So we'll hold for questions from the Commissioners until everyone has spoken.

Carolyn?

MS. KEHREIN: Hi. Carolyn Kehrein, and I'm representing Energy Users Forum.

Oh, thank you, I will. Let's see, I guess I should get situated. Yeah. Please bring the slides up.

MS. RAITT: I am sorry.

MS. KEHREIN: Bring the slides up. Thank you.

So EUF represents a broad group from medium commercial to large industrial customers.

A little bit, sorry, closer? Is that better? Sorry.

EUF represents a diverse group of medium commercial to large industrial customers across a number of industries. I am here today to talk about the impact on electric consumers. And so far we've talked a lot about the Edison billion and the ISO day-ahead market. I wanted to hit a few other aspects.

Let's see. Oops, not that one.

MS. RAITT: Okay.

MS. KEHREIN: That's the prices. There is a .pdf of a PowerPoint.

MS. RAITT: Okay.

MS. KEHREIN: Sorry. Ignore what's up there until she finds it. But, sorry.

So the unusually high prices at the SoCal citygate have significantly increased not just the short-term prices, the ISO day-ahead prices, they've also had a significant impact on the forward curve. And what went up, there we go, what was -- wait, there we go -- sorry about that.

MS. RAITT: I'm sorry.

MS. KEHREIN: Which button?

MS. RAITT: I can --

MS. KEHREIN: There we go. Thank you.

What she had up earlier was a tabulation of the different prices. And I've included that just to show you how the prices have changed over time, but we'll get to that later.

Edison's ratepayers, those of us that are involved are aware of the billion dollar shortfall. But the average customer doesn't see the impact today; they will see it down the road but they're not seeing it as it happens. But there is a group of customers that see the impact immediately, and that is direct-access customers. The reason why the utility customers don't see it is because of balancing accounts and mushing this with that and, you know, all the different shortfalls and over collections get mixed together and sometime down the road it will get put into rates.

But direct access customers, they drive their own procurement, so they're deciding when to purchase. So they are watching market prices and so they have seen forward prices go up and, also, ISO passthrough charges. Those, they don't see quite as quickly. There's like a one- to five-month lag. But still, I mean, compared to the old utility timing, five months of a direct impact is a lot better than what you see as a utility customer.

And I was thinking that Michael Shaw was going to be here and talk about the ways that all these high costs have impacted customers. But just one quick example of what happens when the utility bill goes over, they don't have money to put on their energy efficiency budget. You know, if you have to find money somewhere to pay a really high utility bill, it's got to come from somewhere. And so one of the places it comes from is discretionary capital spending.

But as far as -- could you flip the next one, since I'm really poor at doing that? Thank you.

So where are the increases coming from? Customers buy their power in four different markets. They buy it in the ISO day-ahead market. And because nobody can get their schedule perfect to the, you know, hundredth of, you know, a megawatt, you also buy in the ISO imbalance market, the ISO real-time market. The third place is fixed forward financial contracts and then, also, physical contracts. For instance, a lot of the RPS contracts are long-term physical contracts. So the supply is a mix of those things. And the physical contracts, of course, are normally fixed price.

The other -- so there's the power -- there's the cost of power that direct access customer sees. And then it also sees a number of ISO passthrough costs. One of them is congestion. And earlier today, I saw a slide that had SB 15 pricing. One of the things you need to realize is that there's congestion between SB 15 and the SCE trading hub. So there's additional money that the customers, when you see those prices and the change in prices, the congestion went up, also, so that understates the change. I just noted that when I saw SB 15 prices today. So there's been a lot of congestion.

I just took a little snip there from one of the recent ISO reports. It's a two-year trend by quarter of congestion, so just to give you an idea of how much congestion has gone up.

The other thing is bid cost recovery. ISO recently noted that this year -- 2018 was the highest by a lot since 2011. And then different types of real-time offsets. And once again, they're up about 60 percent this year, so ISO costs have also gone up. So it isn't just the day-ahead prices, it's also the forward prices and the ISO prices.

And I'm glad somebody mentioned, I think it was Mark, this is not just an Edison problem or San Diego problem. PG&E's customers, their costs have gone up, too, because of the way the congestion causes dispatch which then causes a more expensive unit from PG&E to be called on, which then raises the price in PG&E. So everybody is seeing this.

Next slide. Sorry.

What I wanted to do is give you an idea of what the bill impacts really were. So I mocked up three different types of direct access customers here. The first one is what I would recommend which is a balanced approach. You're not betting your horses all on one thing. It's got a mix of the day-ahead, some short-term fix. Short-term fix is, for instance, if you were in November, it would be buying December. So some of it would be a fixed forward price a month ahead. Some of it would be one year ahead. And actually, we buy much further out than that but this is a simple example. And also, you can avoid being in the imbalance market. I assume, just because it was easier, didn't want to make it more complicated, this is just -- I assumed the customer only operated on peak.

What it does is the columns there, one has what the price was for November '16. The other -- next column is November '18. So if you go from 2016 to 2018, for each one of those markets, how did the price change? And so for the balanced approach, the cost of electricity commodity would have gone up 32 percent.

If somebody -- a lot of companies talk about, you know, especially on the gas side, they do index, so I wanted to do an index example. And this one assumes that about half the energy is bought at a fixed price the month before and half the energy is bought at the day-ahead market, and with a little bit of the real-time. That one, your price would have gone up 84 percent from 2016, November 2016 to November 2018. And if you only bought fixed forward, so you locked it all year out, it still would have gone up 50 percent.

Now there's a chart that was put -- was up earlier. But I just wanted to note that the whole fixed price curve has gone up. I mean, just like, for instance, in November, August was up quite a bit. So August, you know, if you compare August from '16 to August of '18 or

August of ‘19, the prices have gone up a lot. So it isn’t just a short-term problem, it’s driven up the whole forward price curve and not just for, you know, electricity, also for gas.

But the point is, is that these are -- have been real -- the increases have been real, they’ve been significant, and they’ve harmed businesses in California.

Sorry for taking a little bit extra time. Thank you.

MS. SPENCER: Thank you.

So we’ll go to JaWaad Malik.

I think I forgot to mention that, as Ms. Carolyn mentioned, that Michael Shaw will not be with us.

MR. MALIK: Thank you. Is the mic distance -- this is fine? Closer? Okay. Better? All right.

Good afternoon, respected Commissioners and Panel. It’s good to be here to be able to participate in this very important workshop. My name is JaWaad Malik. I’m the Vice President of Gas Acquisition at SoCalGas. I’ve had that role for about the last six months. Prior to that, I was the Vice President of Accounting and Finance for SoCalGas.

As a reminder, I am a market participant. And we are an independent body at SoCalGas that operates on the behalf of core customers, both for SoCalGas core customers and San Diego Gas and Electric core customers.

The goal of my role in my organization, Gas Acquisition, is to provide core gas reliability at the lowest cost possible. And we use several tools in order to do so, to help our customers have core gas reliability and core pricing.

I just have one visual that I wanted to share, that will help some of the discussion here.

This is a pretty old chart. Most folks have seen it. But what I wanted to talk about as far as some of the tools and assets we have to protect the core from price variability and provide a low cost is our price supply is diverse across the western half of the basins. We buy gas up in the Canada area, the Rockies, San Juan and Permian Basin. We try to make sure we have a nice diverse supply of gas suppliers. And coupled with that, we ensure that we have adequate interstate transmission pipeline to ensure that we can bring some of that gas into the border areas.

And then coupled with that, we're proactive in ensuring that we have proper BTS or local transmission rights, as well, so we can bring gas from point A to point B, and also limit some of the exposure to one particular point, whether it be citygate or the basin or the border, whatever the case may be, just bringing some diversity to our portfolio.

Also being responsible for the core, we do have core rights to storage. We ensure that we are maintaining those rights as far as their injection rights are concerned and withdrawal rights are concerned to ensure, again, we're providing core reliability and low cost to our customers.

Some of the things that we've done to do so is ensuring that storage levels are adequately being utilized. Although, as we've discussed earlier in some of the other panels, over the last several years, we've had restrictions on Aliso Canyon usage which has restricted some of the flexibility that the core has had in the past to provide, you know, price variability protection during certain times of demand spikes

The other thing the Gas Acquisition Team does, we have a bunch of professionals that are very, very skilled at what they do. And we also have open communication with the PUC, including the Energy Division and the Public Advocates Office, I got that right. And we have biweekly meetings with that body where we talk about some of the things that we're working on as far as strategy is concerned, and also winter reliability which is top of the mind for me and my organization, to make sure we have winter reliability for our customers.

And, you know, we've talked about the pricing issues. We've talked about OFOs. We've talked about infrastructure. You know, what my focus today really is, is an overview of what Gas Acquisition does, our responsibility to core customers, our responsibility to make sure we have core reliability. And also to talk about during times of high demand, like we saw law summer. And when citygate prices can be much higher than border prices, by proactively acquiring various assets, as I described, making sure you have a diverse supply of gas sources, and you have local transmission coupled with interstate transmission, you know, SoCalGas core customers were also seeing certain price increases. But it was mitigated by the fact that we had lots of our purchases in the basin and border areas.

So again, we are not protected from higher prices if it's at citygate, or it could be border. We saw higher prices at the border back in 2014 when we had really, really cold temperatures in the east, so it can flip. But recently, with the higher prices at citygate, we have a portfolio that's been able to protect our core customers from some of the higher pricing and also continue to provide the core reliability.

With that, those are kind of my prepared remarks. And I'll answer any questions, as mentioned.

CHAIR WEISENMILLER: Yeah. This is Bob Weisenmiller again. In general, how does your price forecast match actuals over say your --

MR. MALIK: I'm sorry. Our price

forecast?

CHAIR WEISENMILLER: Yeah.

MR. MALIK: So we receive our forecasting for demand use from an independent department.

CHAIR WEISENMILLER: Really?

MR. MALIK: It's the gas forecast that's provided the day of gas flow. And that is the forecast that we balance to on a daily basis.

CHAIR WEISENMILLER: Yeah. No, my question was if you looked at what you had expected to pay, what your gas procurement costs were expected to be last year, how did you do?

MR. MALIK: Well, we have a mechanism that measures that performance. It's called a gas cost incentive mechanism. Every year there's an annual review of how purchases performed on behalf of the core by Gas Acquisition compared against publicly-provided indices, whether it's inside FERC --

CHAIR WEISENMILLER: Yeah.

MR. MALIK: -- or other public indices, as well.

CHAIR WEISENMILLER: Yeah. But again, I'm just -- we've heard earlier about Edison having a big gap. I'm just trying to understand how you did in a comparable period of time, you know, if you also paid much higher or lower or what?

Yeah, go ahead, Carolyn, if you have the number.

MS. KEHREIN: Well, I just -- from an electric side.

CHAIR WEISENMILLER: Right.

MS. KEHREIN: So having this flow through electric, of course --

CHAIR WEISENMILLER: Well, actually, no. I'm trying to understand their --

MS. KEHREIN: All right. Yeah.

CHAIR WEISENMILLER: We've talked a lot about --

MS. KEHREIN: Okay.

CHAIR WEISENMILLER: -- their core procurement. And I'm just trying to get that number for that.

MS. KEHREIN: Yeah.

COMMISSIONER GUZMAN ACEVES: Mr. Chairman --

MS. KEHREIN: Okay.

COMMISSIONER GUZMAN ACEVES: -- perhaps a more specific question is did you have to trigger on your five percent margin for your gas incentive program? You stayed within the -- you didn't have to put a trigger application because you were out of bounds of your forecast?

MR. MALIK: No, we were not. But the gas purchase, I think you're talking about a gas purchase forecast. That is a regulatory account that we balance against. I do not know offhand how we did versus that. That is something we can follow up with.

CHAIR WEISENMILLER: Yeah. No, that would be good. Just if you could submit it later, that would be good.

MS. KEHREIN: I just wanted to note that from an end use customer point of view and budgeting that this -- the variance between what people thought was going to happen and what happened varied because not everybody did the same thing, but probably about 10 to 30 percent on the commodity they were off in 2018.

COMMISSIONER GUZMAN ACEVES: I guess I wonder, I know, Evie, you provided some recommended solutions earlier, but I wonder, you certainly have outlined the problem but were you -- did you have specific suggestions or recommendations?

MS. KAHL: Ours aren't new. Ours were already mentioned today, which is fix the infrastructure. The system was tight. You know, we don't have surplus infrastructure. We -- and so whenever a piece falls out something happens. And so -- and I -- it was educational to hear what the constraints were in getting the pipeline back in service. And it sounds like at this point there's nothing else we can do but it's doing everything we can do make sure that the pipelines are operating at full capacity as soon as possible. And I support using Aliso, more flexibility.

I mean, the amount of money that it has cost, I mean, we're talking, you know, millions of dollars for particular customers that the improvement -- you know, the $25.00 penalty on OFO and the impact of that on the gas prices that day and the volatility. And the volatility is killing us. I mean, that's something else that we haven't talked about today. But the fact that the OFO penalties are there, it's been increasing the volatility on the basis price. And so I know I'm -- so it's costing us so much, we're having a hard time seeing the benefit that was gained.

And so we hope that some of the proposals that were made earlier today by SoCalGas, as far as getting a little bit more leeway on Aliso Canyon, we'd support that, and also getting rid of the $25.00 level on the OFO penalty. Yeah, that's a thing that could be done right away that we would totally support is getting rid of the $25.00 level on OFO penalties.

CHAIR WEISENMILLER: I'm just going to thank folks. I think we've hit things pretty well in general.

So, Jean, if you have questions, go ahead.

MS. SPENCER: I have one follow-up question. And this is directed at Evie, but if anyone else would like to explain, as well.

This morning Rodger Schwecke was saying that if core had to balance the actuals, then they would be (indiscernible).

COURT REPORTER: Could you speak more directly into the microphone? Thank you.

MS. SPENCER: Do you feel like that is a legitimate concern or what are your thoughts about that?

MS. KAHL: Again, you're asking a lawyer a question about economics. But with that caveat, I guess that's not something I hear inside our group. That's not a dialogue I hear.

What I hear more often is that the core, basically, that the core has access to cost-of-service asset. They have all the storage and they are paying cost of service for that asset. And they are using that asset when there is excess storage capability to trade in the market, so they're driving up our cost by using a cost-of-service asset and charging us market prices. That's the complaint hear more often than if you get the core out there, you know, they'll drive up prices. That's not something I hear.

MR. MALIK: Yeah. I can respond to that.

Again, the basic fundamentals of the core Gas Acquisition Group is reliability for the core and providing lowest prices for our core customers.

When it comes to the asset, I think one thing that's changed since the restrictions on Aliso is our -- the Gas Acquisition purchasing strategies have modified, meaning in the past when we had full access to storage the baseload, which is an annual purchase plan from the border or basin, would be adequate to meet a full year's load because you can balance some of the demand off the storage.

With some of the restrictions in Aliso, to meet winter reliability, as I mentioned earlier which is one of our key goals, during the winter months if there is not sufficient storage, SoCalGas is also -- or Gas Acquisition is also in the market trying to procure gas to make sure that we are providing the supply availability for our core customers.

So back to the OFO and balancing issue, you know, right now the rules are Gas Acquisition balances to a forecast, and that forecast is provided the morning of the gas trading day by an independent function. OFOs are typically called the day before, so an OFO is typically called the day before, the forecast is received the gas day of, and then we balance or Gas Acquisition balances to that forecast. This was under the Omnibus Decision a few years back and that's currently what we, you know, what we participate under.

CHAIR WEISENMILLER: Okay. But how have

you modified your procurement strategy, given the pipeline outages?

MR. MALIK: So --

CHAIR WEISENMILLER: Since you've modified for Aliso, how have you done it for the pipeline outages?

MR. MALIK: Great, great question. As I alluded to when I started my prepared remarks, we have a supply that's very diverse. We have supplies in different areas. We have a lot of interstate pipeline capacity, also a lot of local capacity. Now there is some outages. It's allowed us to make sure that we're all, you know, making sure that the capacity that we have on the BTS, on the local transmission, matches completely what we're purchasing out in the basins with our interstate supply. The interstate supply contracts are something that we're mandated by the CPUC for us to have. By having those flowing supplies, we're able to meet demand.

However, when we look at in the 1-in-35 conditions, that's where we have concern, as well, where without the use of additional supplies or use of storage assets, some of those very, very cool days get very close when it comes to a supply and demand match, so it is a concern.

The way that we're trying to continue to meet demand is, again, procuring at all of our available points, ensuring that we have long supplies. And the only change that I mentioned before is we're purchasing in times where we normally would be relying on withdrawals from the full use of assets, and that's what I meant earlier.

MS. ELDER: Then if I can jump in. Sorry. I'm getting the impression that you're having to buy your last increment of gas at the citygate more often than you used to. Is that a reasonable interpretation?

MR. MALIK: Again, I'll address the question, but just being a market participant, I didn't want to get into any of our procurement strategies. But citygate, along with all of the other different areas that I talked about from supply purchases, they're all part of our portfolio. We do make purchases at the border, the basin, and at times it could be citygate. I can't get into that exact strategy of where we purchase our gas.

MS. ELDER: And then my next question was going to be, have you talked to the Gas Transmission Group and Storage Group about ways that within these restrictions on communication between market participants and the system operator, that you could potentially use some additional space on the system to get a little bit more gas into storage?

MR. MALIK: I heard conversations this morning about some of the ideas on utilizing storage, whether it's shifting storage capability from Aliso into the non-Aliso fields. But the way we're set up today, Gas Acquisition does not have discussions with the operator, so we are not.

MS. ELDER: Okay.

MS. SPENCER: I just wanted to clarify, if you could clarify something you said earlier, which is that you're now purchasing when you would normally be withdrawing. Do you mean in shoulder seasons or in the summer? Sorry. I should be closer to the microphone.

MR. MALIK: So I'll give a general response to that. The purpose of that point was typically in winter, winter months, we rely on storage for normal demand and peak demand. Given the 1-in-35 aspects, there are times where the flowing supplies that we have, coupled with the storage that is available to Gas Acquisition, may not be enough to meet some of the peak demand days. So whether it's usage of Aliso or going out and being involved in active market transactions could be a possibility.

MS. SPENCER: Sorry. Did you mean that you're purchasing in the winter, just in case, more than you would normally be?

MR. MALIK: I'm not saying we are or we're not. I'm saying it's a possibility, given the restrictions on storage.

COMMISSIONER GUZMAN ACEVES: Can I go back to the pipeline question?

And in the first panel, I think it was Evie who suggested potential incentives for the company. And I wondered, did you have specific thoughts?

I was mentioning to one of my colleagues, you know, in the other -- some of our sister agencies on infrastructure projects, they have both carrots and sticks for getting projects completed. And I wasn't sure if you had something specific in mind.

MS. KAHL: No, I didn't. I didn't have any structure in mine. But I just did want to observe that the consequences all fall to customers with none.

MS. ELDER: Commissioner -- oops. Commissioner, that was exactly why I asked the question about the balancing account treatment on non-core throughput. I mean, in essence -- and there are reasons why we have that balancing account protection and I don't want to minimize those. But it is the case that one of the consequences of that is that when a pipeline is out of service, if SoCalGas' throughput is lower, there would be no financial consequence to the company because of that.

CHAIR WEISENMILLER: Yeah. I observed in May, there are code sections that if assets are not being used and useful, that they can pull out of rate base. That came out of some of the reactions to the nuclear plants in the '70s. I'm sure Ms. Kahl might be able to give you the code section cite.

MS. KAHL: Is there a question?

MS. KEHREIN: Commissioner, you bring up

an interesting point, which is a thought that’s been going through my mind. There’s a reason we don’t have way too much infrastructure and that is because you have to pay for it, so you only want enough infrastructure to -- so that when things like this happen, you don’t have price spikes. You just want enough buffer, whether it’s a 1-in-35 or whatever it is you want to build to protect.

And unfortunately, the way our system is set up, if somebody makes a mistake, if an investor-owned utility makes a mistake and over-forecasts and builds more than they need, they’re at risk, so they’ve got this big stick. There’s no carrot for them but there’s a stick as far as not overinvesting. And as a ratepayer, I don’t want them, you know, I don’t want them excessively overinvesting.

But we went through this over a decade ago on the electricity side where, you know, where there were a lot of things, a lot of different passthrough costs and prices that were high because we didn’t have enough infrastructure. And now we have more transmission, we have, you know, generators that are more appropriately located.

And the same thing, when you think about San Francisco when they, you know, (indiscernible), oh, no, you know, no more. We're not going to have any transmission lines. We're not going to have anything. But they don't get it; you don't have it, you don't have power. You've got to pick.

And so with respect to Southern California and the opposition to Aliso, if it isn't going to be Aliso, it's got to be something else. I mean, we need more infrastructure in Southern California than we currently are using, even if the pipelines are back in. And so, I mean, that's -- people have to think about, you know, if we aren't going to put Aliso back in, I'm sure they don't want an LNG facility, you know, in Long Beach to bring natural gas on the 1-in-35 days. So I mean, it's just -- and I don't think -- it's hard to build more pipelines, so I don't think we're going to get more pipelines.

So I think to some extent you have to pick the lesser of the evils, even if, you know, for those that think Aliso Canyon is evil.

CHAIR WEISENMILLER: If this is done, we'll get to public comment. Any other questions for this panel? Thank you.

And as I said, Porter Ranch. Let's go to public comment. And I have a blue card from Porter Ranch. Please come up.

MS. RAITT: If you could go to the center?

CHAIR WEISENMILLER: Yeah. If you go to right there, that's great.

MR. NAJM: Good afternoon. Good afternoon. My name is Issam Najm. I'm the President of the Porter Ranch Council. And I appreciate the time to be here. And before(indiscernible), Aliso Canyon is evil. We're good? That? Okay.

I know I have three minutes, so I will do my best because I have a lot to say.

I've never been to a workshop where the main point of the workshop was made in the first slide of the workshop, and that was the relationship between the prices that we ratepayers are paying as a function of the pipeline outages.

You know, people have gotten married,

conceived, had babies, baptized them since that pipeline has been out, and it's still out. I do not understand, where is the level where you say enough is enough?

As a ratepayer, we're looking to you to be the body that tells them, here's what needs to happen and there will be consequences. I look around the room, everybody in the room is hurting except one entity, SoCalGas. There is no consequence to them for any of this, of these events, and we are still simply asking them, when will it be back?

So I would implore you to say this is when we need it to be back. And if it's not back at that date, you should have the authority to impose consequences on them. They are the only ones that are not hurting in this room.

We went through a Northridge Earthquake with pipelines busted and buildings fell down all over the place, the entire valley, and we were back in a lot faster time than a year-and-a-half, which are still waiting for. This is inconceivable to me.

And to say that it's too dangerous to work in the desert, maybe it is time that you hire someone else to do that work and send the bill to them. Because if it weren't sad, I would be laughing, but to say that this is because it is too dangerous to work in the desert, I mean, who buys that?

And also I would like to suggest that maybe you can walk over to the Fish and Game and ask them directly, when did the application for the permit come in? What was the process? Why did it take this long? And have it come directly from them, not from the person who's telling you that story.

You know, we have an alcoholic in the room and we're simply asking them to hand over the bottle. We need to take it.

Thank you.

CHAIR WEISENMILLER: Thank you. Any other public comment from anyone in the room?

You want to check the phones?

MS. RAITT: Yeah. Anyone on WebEx, if you can use the raise-hand function?

Otherwise, we'll go ahead and open up the lines.

(Background WebEx conversation.)

MS. RAITT: So I'm opening up the lines,

so if you don't want to make a comment, please mute your line. I don't think --

(Background WebEx conversation.)

MS. RAITT: I don't think we have any comments. I don't think so. Do you have any? We don't have any from --

CHAIR WEISENMILLER: Great. Let me start out and say I think, you know, I'd like to thank everyone for their participation today. I would like to remind everyone that we have a written comment period.

And, Heather, could you remind them of the date again?

MS. RAITT: Yeah. January 25th, written comments. And I'd just like to note that we do have all the presentations posted on our website now.

CHAIR WEISENMILLER: That's good. And you know, again, I think this has been informative. I certainly would like to have people's comments on specific solutions going forward. And you know, again, encourage people to be creative on thinking through these issues. Obviously, difficult time. We're trying to come up with ways to move forward, you know, particularly on trying to deal with the price issues. But certainly, I think the issues have been framed pretty well, depending upon what happens, just in terms of what we're going to do for the rest of the winter in terms of supply.

COMMISSIONER RANDOLPH: Yeah. I want to thank everybody for participating. It was useful to hear thoughts about possible solutions. I think Dr. Najm raises a good point, that getting the pipelines up and running is the most critical step, but there are some less, sort of quicker-term options we can take a look at, least for winter reliability, so we will certainly be thinking about all of those as we move forward. And I really thank everyone for all the input you've provided.

COMMISSIONER DOUGLAS: I just also appreciated the comments and the input and appreciate everyone being here.

COMMISSIONER GUZMAN ACEVES: Thank you, Mr. Chairman, and to President Picker for putting this together so we can have this dialogue. And I certainly heard a lot of things that we can move on quickly. And I know that in our brief conversations, it's something -- there are things we can act on that we need to very quickly, and some longer-term solutions regardless, actually, of the supply issue to really make sure we keep some pricing constraints.

So thank you for your time and your continued involvement. And if you have some even more creative ideas or you have some thoughts on your way home, please send them in. We do -- we don't actually read them all the time but our staff does and they tell us some of the great ideas you have, so thank you very much.

MR. RIDER: Okay. Not much to add, just thank you all for coming here today and helping us figure out potential solutions and helping us understand some of the issues a little bit better.

CHAIR WEISENMILLER: The meeting is adjourned. Thanks.

(Off the record at 2:31 p.m.)

REPORTER'S CERTIFICATE

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

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