DOCKETED

Docket Number:	16-IEPR-02
Project Title:	Natural Gas
TN #:	212396
Document Title:	Transcript of the 06/17/2016 IEPR Workshop
Description:	2016 INTEGRATED ENERGY POLICY REPORT (IEPR) WORKSHOP ON TRANSPORTATION FUEL SUPPLY RELIABILITY DUE TO REDUCED NATURAL GAS AVAILABILITY IN SUMMER 2016
Filer:	Cody Goldthrite
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	7/22/2016 1:50:16 PM
Docketed Date:	7/22/2016

CALIFORNIA ENERGY COMMISSION

IEPR COMMISSIONER WORKSHOP

In the Matter of:	) Docket No.
	) 16-IEPR-02
	)
	)
	) WORKSHOP RE:
	) Transportation Fuel
2016 Integrated Energy Policy	) Supply Reliability Due
Report Update (2016 IEPR Update)	) to Reduced Natural Gas
________________________________	) Availability

2016 INTEGRATED ENERGY POLICY REPORT (IEPR) WORKSHOP ON TRANSPORTATION FUEL SUPPLY RELIABILITY DUE TO REDUCED NATURAL GAS AVAILABILITY IN SUMMER 2016

DOUBLETREE BY HILTON SAN PEDRO

2800 VIA CABRILLO-MARINA,

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FRIDAY, JUNE 17, 2016

10:00 A.M.

Reported by:
Steve Hopkins

APPEARANCES

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Robert B. Weisenmiller, Commission Chair

Janea A. Scott, Lead Commissioner for Transportation

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Workshop Presenters (* Via telephone and/or WebEx)

Catherine (Katie) Elder, Aspen Environmental Group

Gordon Schremp, Energy Assessments Division, CEC

Greg Reisinger, California Public Utilities Commission (CPUC)

David Hackett, Stillwater Associates

John T. Hansen, Western States Petroleum Association Antitrust Counsel

Discussion Panel

Moderator - Gordon Schremp, California Energy Commission

Jolie Rhinehart, Philips 66

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Public Comment

I N D E X

I N D E X (Cont.)

P R O C E E D I N G S

JUNE 17, 2016 9:35 A.M.

MS. RAITT: Good morning, everyone, to today's workshop on Transportation Fuel Supply and Reliability Due to Reduced Natural Gas in Summer 2016.

Today's workshop is part of the 2016 Integrated Energy Policy Report Update or we call it the IEPR for short.

On to some housekeeping items, bathrooms are down the hall on the right. Please be aware this workshop is being broadcast through our WebEx Conferencing System and it is being recorded. And today we have a live webcam that we're hoping that the remote participants can see what's happening at the front two tables. So the Commissioners and the presenters will be on a live cam and the folks that are remote participants can see a split screen of the presentations and the front tables.

We'll post an audio recording in a few days and a written transcript in about a few weeks. And I'd like to thank our presenters for being here today and agreeing to present, and request that you do stick to your allotted time. And I'll be reminding folks during the day of our time constraints.

At the end of the day there will be an opportunity for public comments, which will be limited to three minutes per person. And Kevin Barker -- Kevin, if you could raise a hand -- is the person to talk to if you'd like to make comments. Just give him your name and affiliation. And then after we take comments from folks in the room we'll go to WebEx and you can use the chat function to let our operator know you'd like to make comments.

Materials for today's meeting are posted on our website. All presentations are available on the website as well as the agenda and the notice availability.

We welcome written comments. They're due on July 7th and the notice for the workshop provides information about how to submit written comments.

And with that I'll turn it over to Commissioner Douglas. Thank you.

COMMISSIONER DOUGLAS: Thank you very much Heather.

I am Karen Douglas. I'm the Lead Commissioner for the Integrated Energy Policy Report Update, this year. And appropriately, one of our major focus areas in this year's EIPR Update is the Aliso Canyon gas leak and the implications of that leak.

And so today, the focus of this workshop, which we really put together in response to comments by the Western States Petroleum Association, expressing concern about the reliability of natural gas and electricity supplies and how those could affect and what implications they could have, for transportation fuel production. So in response to those comments, we are having this workshop focused on those specific topics.

And I appreciate the work that's gone into the materials and the presentations for us today. This is obviously a very important topic and we're happy to be here today. So with that, let me turn this over to the Chair for his opening comments.

CHAIR WEISENMILLER: I'd like to thank everyone for being here and their attention, and certainly the staff and the Chair and Commissioner Scott for organizing this.

Coincidentally, yesterday ISO announced sort of a restrictive maintenance alert. And at the same time basically there is a weather forecast that's relatively ominous for very high temperatures throughout at least the southwest and may go also through the plains. It's anticipated L.A. could be 100 or more on Monday and Tuesday.

And so at this point we're anticipating if the weather forecast holds to be correct, which obviously is anyone's guess, that there will be a Flex Alert on Monday and Tuesday.

And as said coincidentally, we're talking in this workshop about the impacts of Aliso Canyon on sort of the refinery sector. And obviously this could be a severe test of the system to have to deal with very high loads, without Aliso Canyon as that buffer. And so, with the Flex Alerts, we really want to ask everyone to do everything they can do conserve energy.

Indeed, I sent a letter out to state agencies today with facilities in Southern California, urging that they do so for Monday and Tuesday. Obviously, if you're thinking of buying say LEDs, let's do it this weekend and get them in. But in terms of operational stuff, on Monday, certainly the more people can reduce lighting, increase thermostats, defer major appliance operation: dishwashers, washers, recharging your electric vehicles until we're past the conditions.

But certainly just stay tuned to the television or radio and if you hear the Flex Alerts then take appropriate action. So thank you.

COMMISSIONER SCOTT: Good morning, everyone. And thank you so much for being here today. I want to echo the thanks that the chair gave to our staff for putting together an excellent workshop for us.

As you all know, today's workshop will explore the potential impacts of possible natural gas or electricity curtailment due to Aliso Canyon on refineries in Southern California. And we will also explore mitigation strategies that may be implemented to minimize the possible impacts of those potential curtailments. And so I am very much looking forward to the presentations today and the information that we'll get.

And so I saw a few people come in after Heather made her announcements, so I'm just going point out Kevin Barker one more time. If you are a member of the public and you'd like to make a comment, please be sure to let him know so that he can let us know. And with that I'll turn it back to Heather to kick off our workshop.

MS. RAITT: Great. Thank you.

So our first Katie Elder from Aspen Environmental Group.

MS. ELDER: Good morning, Commissioners.

MS. RAITT: So Catherine if you can just let me know when you want to switch slides I'll do that.

MS. ELDER: I was just going say Heather's going to advance the slides for me and I'm inevitably going to forget to tell her to. So can we go to the next slide?

MS. RAITT: Yes.

MS. ELDER: I'm going to try to really quickly give you a quick overview of what we've done, what's going on at Aliso Canyon, and where we are with the Action Plan. And then talk about potential impact to the refineries.

So as most everybody knows by this point that leak got detected on October 23rd. There were a number of attempts to kill that well from the top. They all failed. We ended up having to drill -- SoCal ended up having to drill a relief well and ultimately was able to stop the leak in February.

There's still an investigation going on about the cause. And we don't really know yet what went wrong. Although it's going to be very interesting to find out exactly what caused this problem.

I was part of the team, along with other folks at the Energy Commission with the PUC, DWP, LADWP and ISO, that developed an Action Plan to try to preserve electricity and natural gas reliability for this summer. We're working on what we might do for the winter still. We released that Action Plan in early April. And this weather situation Monday, Tuesday into next week is going to test our Action Plan -- for sure going to be a test for the Action Plan.

We also posted an update to that Action Plan. We added some additional mitigation measures in late May, in response to stakeholder comments, which also got us to today's workshop.

Next page, see I remembered.

Just a few essential background facts, Aliso

Canyon represented about 45 percent of SoCalGas's overall gas storage capability. It was the only large storage facility within the L.A. Basin and was really critical to SoCalGas's operation within the Basin including in the summer, which surprised people. People didn't realize that. They thought storage was used in the winter, but in fact SoCalGas also needed it for the summer, operationally to meet daily peaks, intra-day peaks, on a relatively routine basis.

And so it remains essential for meeting winter demand. And we're going to get to our winter analysis. I think that workshop is on August 12th.

During the summer when we use it to help support electric reliability, that includes support to 11,000 megawatts of generating capacity in the L.A. Basin: 40 percent of that belongs to LADWP, 60 percent is in the Cal ISO's -- I shouldn't say it belongs to LADWP. It's in the LADWP balancing area, some of which is owned by DWP, but there's some other municipals in that balancing area -- and then 60 percent is in ISO's balancing area.

What it is particularly used for is to make up for system imbalances. And that's going to sound a little bit nerdy, or maybe I should admit that that's gas nerd talk, but non-core customers have to order and schedule their own gas. They buy it themselves. They have to call up and order. Actually they don't call up; they probably submit it electronically -- what we call a nomination -- to say, "I'm going to use X amount of gas today." And then what happens is they may or may not use that "X" amount. That difference would have been made up with gas from Aliso Canyon. So that's what we're missing is the ability to make up for those imbalances.

It would also support rapid ramping during the day. Next slide.

The technical analysis that the four agencies worked on showed that this issue about imbalances was what exposed us to reliability risks. The difference between the scheduled gas and the actual gas demands -- that imbalance, if you will -- could be as small as 150 MMcf per day on a day when demand might be over 3,000 MMcf, for example.

If you combine a relatively high-demand day over amount of peak-demand day with that kind of differential, we end of with the gas system being under stress. Which means that the gas operators have fewer and fewer tools that they can use to fix upsets during the day or fix a change in circumstances during the day.

If you layer on top of that planned and unplanned outages that inevitably occur, such as say an engine on a compressor station goes down, those sorts of planned and unplanned outages on top of that differential would then get us into gas curtailments.

Let's go to the next slide.

And so at the bottom of this slide, we actually showed the scenarios that I was talking about where we could have a mismatch between scheduled gas and actual gas demand. And those things accumulate in our force scenarios to where could be ultimately needing to reduce gas demand or curtail gas demand of about 1,100 MMcf per day.

The analysis that the team conducted suggested that there could be 16 summer days of gas curtailment, due to these kinds of events, these scenarios, during 2016. If gas has to be curtailed, then the electric generators would be forced off the system.

We also confirmed that shifting generation to San Diego doesn't help us very much, because that's also served off of SoCalGas's system. And so you get back to the same problem.

Of those 16 days, 14 days could be large enough, in our scenarios -- we get past Scenario 1 there -- that the electric system could absorb. But on those other three scenarios as the gas curtailment gets larger the electricity system would not be able to reallocate, re-dispatch, import more electricity, depend on demand response. And so we would end up with electricity system curtailments for as the electric operators say from load shed. Next slide.

This is a list. I'm not going to go through this list, but these were the original mitigation measures that we included in the Action Plan. We've got three more mitigation measures.

I can also report to you that LADWP was successful in getting an exemption from the South Coast Air Quality Management District to allow them to burn some diesel fuel in their power plants, which will help enormously if we actually get past our Scenario 1 and into actual potential for electric load shedding. Next slide.

The current situation at Aliso Canyon is we've got about 15 billion cubic feet of gas there. The Action Plan called for us to be able to use that gas to help mitigate electricity curtailments. We are still in the process of implementing the safety review. That's still underway. All 114 wells have to pass the safety tests or be isolated from the rest of the field.

DOGGR has to also hold a public hearing once SoCal's gotten to a point where they say they've done enough that they would like to start reinjection.

We do not know when exactly that will happen. And we don't know what the result of that public hearing will be. In the meantime we could only withdraw from other wells if DOGGR approves that, consistent with the finding of that. The existing wells or available wells were demonstrably insufficient to support reliability. I believe that that DOGGR approval has been granted and is in SoCal's hands now.

As of yesterday -- I believe it's the case that a total of nine wells have been fully inspected -- and are available for withdrawal. Although not all of that nine may be actually reconnected via plumbing to actually provide withdrawal.

In any case the wells that we expect are probably not going to get us up to Scenario 4 of our four curtailment scenarios. We think what we may end up being able to cover Scenario 2, maybe even Scenario 3, but we're not going to get to Scenario 4. Of course, Scenario 4 is the lower probability scenario where a combination of things go wrong. Rather than one or two or three things going wrong that's four or five things going wrong. Next slide?

And this is really the bottom line or cutting to the chase there. In the Action Plan we tried to preserve -- do as much as we could be coming up with ideas to make sure that we've preserved electricity reliability. And so the Action Plan expects the electric generators would be curtailed first. In the modeling that we did, the magnitude and the days that we looked at to create our scenarios, the magnitude of the gas curtailment was never larger than the electric generation load.

That doesn't mean that it won't be in reality, it just means that in the scenarios that we looked at the electric generation load was always large enough to absorb the curtailment. We never got into the rest of the non-core load.

In that analysis the ISO also was careful to exclude the cogeneration load from the EG load, because a number of the refineries have cogeneration facilities. So in trying to spread around the impact of gas curtailment, the cogen load was protected.

So we think that under what we set up in the Action Plan the electricity outages would occur and we'd end of with the electric side absorbing all of it or moving it from load shedding before we ever got into curtailing gas to refineries.

That being said, we think there's still some exposure to gas curtailment to the refineries. It depends on really what happens with the size of the gas curtailment, how big does the gas curtailment end up being, which of our scenarios do we get into, what are the exact circumstances on those days and how large that gas curtailment is relative to the size of the electric generation load.

It's possible. It's not probably, but it's possible that the gas curtailment could be large, but maybe it's a day when EG demand is small. Not Monday or Tuesday when we know EG demand is going to be large, but that is possible.

We are also not exactly sure how much gas we're going to be able to pull from Aliso Canyon when. It's also going to depend where on SoCal system that pressure deviation that leads to curtailment ends up being. In some of the scenarios we've seen with the hydraulic modeling that could occur near El Segundo. So even if we're able to spread things around and we have good balancing from people, on a high-demand day with stress on the system, we could end up with a pressure drop that actually occurs near of where some of the refineries are.

The last point I'll mention is that on the electric side there is a mechanism in place, under a CPUC decision adopted in 2001, that allows the refineries to apply for an exemption from electrical outages, so we think we have them protected on the gas side. Although with the caveats that I mentioned on the electricity side they can apply to the utility for an exemption.

I know that the utilities, Southern California Edison, as well as LADWP, have looked at the exemption lists and tried to make sure that they have the right facilities on the list.

So with that, I will ask if you have any questions that I can try to answer.

MS. RAITT: All right, it sounds like we don't.

Thank you, Catherine, for your presentation.

And next we have Gordon Schremp from the Energy Commission.

(Pause to set up for the next speaker.)

MS. RAITT: So just quickly, I saw a question in the audience. We're still going to have Katie here, so when we get to the period before lunchtime we'll give you a chance to ask your question. And others who have questions of panelists, just write them down and we'll do our best to give everyone a chance to ask those questions.

MR. SCHREMP: Good morning, Chair, Commissioners. Thank you, Heather. Welcome everybody to the workshop. Thank you attending.

We do have a great deal of information, so my comments are going to be sort of split into two parts. The first is going to be a little bit of an overview of the refineries, sort of a refinery 101 review, just for context-setting purposes. And then I'll be talking about the results of our analysis of refinery fuel use that does include purchased natural gas germane to the concerns just discussed by Katie as well as other types of fuel they use still gas, and in some case liquid fuels that are gasified.

So we want to present that information so that we have some additional details on quantity of natural gas used and variability throughout the year.

So next slide, please? And we'll just skip that to the next one.

So the system is basically for refinery -- or transportation fuels is an interconnected system. The refinery serves as sort of the central nervous system. Everything goes out from there: inputs via pipeline, marine terminals, outputs via pipeline, but the whole system is essentially in motion pretty much 24-7 all the time. Next slide please.

We also want to point out that the fuel system is really a regional West Coast system. There are products that flow from the Pacific Northwest refineries down into California. We also supply, by marine vessel, to Oregon; more extensively by pipeline to Nevada and Arizona. So there is an inter-dependence on the refineries in Washington and California for adequate supply of transportation fuels.

Also, I want to note that there is no pipeline connection between Northern California refineries and Southern California. These movements must be by marine vessel almost predominantly. And that's that little bar.

(Technical problem: audio cuts out for 3 minutes.)

COMMISSIONER DOUGLAS: So Gordon, before you speak, just to let the audience know we looked again at the agenda. And what we're going to do is if you have questions of the first two presenters -- and assuming we're not so overrun with questions that it will push us way, way over time, which I don't think we are -- after Gordon speaks, we'll give people a chance to ask any questions they might have of the first two presenters before we move on.

Go ahead, Gordon.

MR. SCHREMP: Thank you. So I think we're on Slide 6, which talks about the California refineries. And in particular the means of conveyance of the crude oil they received during 2014, so most of the crude oil does arrive into California refineries by marine vessel -- over a million barrels a day for 2015 -- to a lesser extent crude oil from California sources obviously by pipeline, and to a much less extent crude oil that's brought in by rail. So next slide please.

So here are the locations of the six primary refineries in Southern California producing California specific fuel. There are some other smaller facilities that do produce asphalt, lube oils, and some other solvents. So here are the primary facilities and their crude oil capacity.

Just to show you that there is a cluster very close to Long Beach. Katie mentioned a portion of the natural gas distribution near El Segundo. That would be where the Chevron El Segundo refinery resides. Next slide please.

So looking at how much fuel they produce you see gas refineries in California are large gasoline producers. Clearly that's the primary fuel of choice for transportation in California -- about 40 to 42 million gallons a day.

Diesel fuel is about one-quarter of that, so they produce a disproportion of gasoline designed to try to meet demand. There's also diesel fuel produced and jet fuel you see from the pie chart.

And export fuels are primarily exported via pipeline to Nevada and Arizona with some volumes going to Oregon, via marine vessel as well as foreign destinations, but they're very modest. Next slide please.

This is just meant to convey that refineries have a lot of process units that are designed to change the composition structure, combine smaller chain hydrocarbons together to make longer chains, break up hydrocarbons. And so they use a variety of techniques to do that, a lot of heat a lot of pressure, a lot of catalysts, and a lot of hydrogen. Next slide please.

There is also a need for the refineries, which are extremely complex to operate in balance, meaning they have to make sure the steam, heat, electricity loads are all in balance. That has a lot to do in the case of these fuels we're talking about, the quality of the fuels, the BTUs the source of those fuels.

And they have a lot of outside utilities, outside the refinery gate that they don't control -- that in some cases do -- can be a source of potential rotating outage impact that they depend on. We're hoping to get some of our panel members to talk about that a little bit.

There's also the case of third-party hydrogen producers that are outside the refinery gate, not owned and operated by the refineries that they depend on for hydrogen supply as well. Next slide please.

So this isometric is meant to illustrate the two primary types of fuels we're looking at, which is basically the primary types of fuels. I don't want to convey that there are others: it's natural gas and still gas.

And if Heather could go to almost the very end, we're going to just skip ahead. I wanted to show the audience something -- the first of our extra slides.

So this is just meant to show that there are differences in the quality of these fuels used by refineries. Purchased natural gas is on the right hand column. And the refinery gas or still gas that is produced in the refinery by processing crude oil and operation of other process units is of a different quality. Clearly highlight it's not mostly methane; it's only a portion of that. A lot of hydrogen is in there, a lot of other constituents.

So from the perspective of say more pure processed natural dry gas that's purchased from the utility, it is not that. And it does not create some handling issues within the refinery and quality issues that limit how flexible still gas can be used in different end uses within the refinery. So go back to the previous slide please.

So the California Energy Commission collects a lot of data from the refineries: weekly, monthly, annual. However we don't collect a great deal of fuel consumption data from the refineries. And certainly not with the specificity of how that fuel is used within the refinery under various categories. So those categories are illustrated here as hydrogen production, cogeneration for electricity, boiler to make steam for process steam in the refinery, as well as furnace heaters to heat up the crude oil and intermediate products.

So we had to conduct a survey of the refineries to obtain monthly data going back to January 2014. This is called an Ad Hoc PIIRA Confidential Survey. PIIRA stands for Petroleum Industry Information Reporting Act.

So we issued the survey request last Monday and received the last of the surveys yesterday, so I want to thank the industry for being so responsive and 100 percent compliant. So this allowed us to bring some detailed information to this proceeding that we think is important for people to see. Next slide please.

So this shows the natural gas quantity, average quantity, and still gas quantity side by side one month to the next. And you see there it does go up a little bit in the winter months and it does go back down.

And the numbers are broken out as the ratio in any particular month, the lowest being 40 percent natural gas. So that was more still gas that month. And the highest was May of 2014 where you had 57 percent was actually natural gas.

So some differences in still gas availability obviously are linked to refinery operations. If my crude unit is down I'm not producing as much still gas. And so you can have in-source changes in the amount of still gas available for other process units. Next slide please.

So most important -- how much natural gas are the refineries using? So as a percent of total SoCalGas system send-out it does -- in this time period did max out at a little over 13 percent and the lowest point was actually 9.4 percent. So you can see variability from one month to the next, as a large end-use customer, that in some cases is always refinery operational-based.

And you can have significant unplanned outages that lower this amount. You can have refinery operations that come back online and will increase natural gas loads or demand for the refinery. So it isn't a quite steady state, as you can see from these numbers, but we wanted to share that. So next slide please.

So we have to say 2015 was an atypical year, quite remarkable. Not for consumers certainly in the pocket book, because of the significant amount of unplanned and even planned maintenance that took place in 2015. And it was to the point of averaging about 170,000 barrels a day of gasoline production capability offline. So why is that important? Let's go to the next slide.

That is important because how much maintenance they're doing planned or how much unplanned activity there is at the refinery, does have a material impact on the amount of natural gas they need at the facilities.

So we look ahead to see -- and the orange dots on this slide are actually not planned maintenance -- and the takeaway is that if you look at the shaded areas that's how high they were in 2015. So FCCU stands for Fluidized Catalytic Cracking Unit, the primary gasoline producing process equipment at the refinery. You see that that was almost unprecedented in the history of over the last ten years of the amount of gasoline production capability offline. And so that means their demand for natural gas was lower than it would have been. Next slide, please.

MS. RAITT: Just to let you know you have five minutes left.

MR. SCHREMP: Okay.

So the dark blue line is 2014 natural gas use by month. And the dotted blue line is 2015. So the takeaway is looking ahead for 2016, we're not going to have that level of significant planned maintenance as scheduled. And so the natural gas demand by the refinery sector is going to be probably closer to 2014 -- not artificially lower as it was in 2015. Next slide please

So here are the numbers broken out in terms of averages per day you can see, remarkably similar in terms of the natural gas used by the four end-use categories. Predominantly it's cogeneration followed by hydrogen. The least amount is boiler fuel. This is for natural gas. It's different for still gas. Next slide please.

This is the relative concentration or ratio of natural gas to refinery still gas and you see co-generation, hydrogen, very high ratios, over to and sometimes almost as high as 5. And lower numbers below 1 meaning more still gas is in that mix that goes to heater fuel and boiler fuel than purchased natural gas. This is quality based. You have to have certain quality specifications to be able to meet the needs of your cogen units as well as you hydrogen plants. Next slide please.

So those are the basic numbers and the breakdowns. However, I have to point out that the refining industry does have, as I mentioned earlier, very important third-party hydrogen producers outside the refinery gate that -- oh by the way -- also use natural gas. We do not have their data at this time. And so that would be an additional natural gas demand in SoCalGas's system for refinery-based activities that are not included in our percentages we presented earlier. Next slide please.

Last slide in my main presentation is operational flexibility. We also asked the companies, "Well, how much less natural gas could you purchase and still sort of operate normally?" You have some flexibility within, so what does that kind of look like? And so the grand totals are about 46 to 52 million cubic feet per day. That's about 15 to 18 percent of their purchased natural gas. And so if they're 9 to 13 percent total you can do the math and see how much it is with the total system.

But I wanted to also point out that none of the respondents can do completely without purchased natural gas and continue operating normally. That's not the case, because the natural gas purchases are so large.

There's also the ability for some of them to use say propane and butane, gasify it and use it as a heat-source fuel. And that is limited because of plumbing, their architecture within the refinery, as well as just flat-out the supply of butane and propane on a seasonal basis. So there is limits to this, but so there is some flexibility, but it's not indefinite and it's not very large based on the analysis we performed. Next slide.

And that's it. I'd be happy to take any questions you might have.

CHAIR WEISENMILLER: Thanks Gordon, a couple of questions.

First one is sort of an open question of do you have a sense of much of that extracurricular gas for hydrogen, what that load might be or a guesstimate shall we say?

MR. SCHREMP: No. No, I don't. But maybe that's something Katie could help with right here and now? But it's something I think we have the ability to reach out to the industry post workshop, in some form of follow-up analysis, to try to get a better quantification around that question.

CHAIR WEISENMILLER: I think the other question is -- and I'll frame it two different ways -- one of them is one of the obvious lessons from the Aliso Canyon leak we need to do something in Southern California to reduce our reliance on Aliso Canyon.

And the related issue is that things may or may not be tough this summer. It's more of a question of variability on hourly and a mismatch, but the storage fuel is primarily designed for covering core loads in the winter.

And so obviously we are moving forward from looking at the summer's issues to next winter's issues having a workshop coming up in April -- or this August -- excuse me. So the issue certainly coming up then and what we're starting to think about is, what can people do to reduce their gas loads between now and next winter? And so that -- not just the sort of, "Okay, we're in trouble, how much can you drop today?"

But are there things that can be done between now and then that sort of move us away from an over-reliance on Aliso, particularly if we have a really cold -- basically Aliso is sized for a one in thirty-five cold month. So it's really, really cold.

We've had colder years than that. If you look at 1948 throughout the entire West it was like three standard deviations. So bottom line is that coverage, I think it probably behooves everyone to start thinking about ways to reduce gas use next winter.

MR. SCHREMP: And I think we do understand this is sort of a two-part issue. It's the here and now summer and then -- but it's don't forget natural gas demand is typically higher in the winter months.

So I think what's important -- one of the slides I had up there is -- why we're looking at their planned maintenance that's coming up, is when they're down for planned maintenance, they're going to be using less natural gas. And so the refiners clearly know when they're conducting planned maintenance.

And this is something that may be very useful to a natural gas supplier to have maybe sort of a scheduled demand, a range of demand that the refiners could have, based on planned maintenance that's coming up. Certainly that kind of information is very sensitive business information. But if that kind of information could be looked at in aggregate there might be some interest to SoCalGas that they could say, "Well, it looks like this'll be helpful in February of 2017."

So we're just suggesting that refiners do know, in advance what planned maintenance activities are going to take place. They do know what kinds of changes in refinery operations will be as a consequence meaning purchased natural gas being lower than it normally is. So that may be some useful area of information going forward for the question that how much demand from this end use there might be in the winter months.

CHAIR WEISENMILLER: Yeah, that's good.

I think the other part of the discussion, which certainly is more an internal refinery operations and/or conversation -- SoCalGas is their equivalent of -- what can they do through say energy efficiency to reduce their gas demands between now and next winter -- their equivalent of LED light bulbs or whatever in the refinery.

And then what do we need to do institutionally? To the extent that PUC has a lot of unfunded energy efficiency funds obviously we're shifting that to the low-income areas too. But are there things we can to do really reduce the energy efficiency their requirements for the gas next winter?

MR. SCHREMP: That certainly merits a further discussion. It's our understanding on working with the refineries over the years, especially AB 32 related, the Air Resources Board and the South Coast Air Quality Management District emission rules, that the refineries have actually undertaken a number of efficiency projects within the refineries. These are usually low-hanging fruit that have an immediate economic return. And so these kinds of more modest capital projects do get funded. So they have become much, much more energy efficient over time.

And so is there room for additional projects? I don't know the answer to that question, but maybe that's one of the companies here could weigh in on sort of how much energy efficiency has been undertaken and maybe what other options there might be, between now and this coming winter.

COMMISSIONER DOUGLAS: All right. At this point I think we don't have any more questions from the dais. So if there are questions from the audience for either the first speaker or for Gordon, please come forward?

This is not the time for public comment. This is a time for technical or clarifying questions and Katie if you could come up to the table that would be great.

So when you come up to ask a question, please identify yourself for the record and go ahead.

MR. MITCHELL: Hello. My name is Marcus Mitchell.

And you mentioned earlier that there was still 15 billion cubic feet of gas at Aliso Canyon. I was just curious what that number represented as a percentage of the capacity prior to the leak?

MS. ELDER: The total capacity, working gas capacity, at Aliso Canyon was 86 Bcf, so 15 over 86 -- and I'm not going to do that math in my head.

COMMISSIONER DOUGLAS: Thank you. And if you could provide a card to the court reporter when you have a chance that'll ensure your name is spelled right and your title and so on.

So are there any other clarifying questions of the first two speakers? Please, come forward.

MS. TAYLOR: Good morning. My name is Simone Taylor. I'm with the Los Angeles Department of Water and Power.

I had a question of about the wells. What does it take to isolate a well? There's 114 wells, so what would it take to isolate the 9 wells that have been tested or inspected, sorry? Thank you.

MS. ELDER: The wells ultimately that you would expect to be isolated would not be the wells that got fully tested. The idea is that we want to get wells tested and through the safety review and then be able to use them.

The wells that would be plugged or isolated would be wells that it's going to take longer to get them through the testing process. And over time SoCal, as I understand the inspection plan, Safety Inspection Plan, will continue to review additional wells each month. There's only so many that they can test at a time. They can only get I think it is eight rigs onsite at Aliso Canyon at a time, so it's just going to take several months to get through.

To isolate a well essentially what they do is plug it. So they'll pump it full of liquids and other things that I'm probably not really qualified to talk about, that will prevent any gas from flowing up through the tubing or the casing.

CHAIR WEISENMILLER: I was just going to note that at least initially my understanding was that there are wells in the field, which are of the same tranche or characteristics as the well that leaked. And the notion was that to plug those, assume that they're never going to come back or if they do come back it's going to take more time in terms of testing and making sure they're really operational.

So it was like given 114, given as Katie said about 9 a month, the notion was let's take what we think are the worst ones and put them aside. And start marching through things, so starting with what we think are the best wells.

MS. ELDER: That was my understanding too, that there's about 20 wells that were actually out of service at the time that the leak occurred. And that SoCal was going to permanently plug those. And what I've heard the gas engineers say is that that probably involves concrete in the well bore. But again, I'm not that kind of expert.

MS. RAITT: Commissioner, we actually have one on from WebEx.

COMMISSIONER DOUGLAS: All right, go ahead from WebEx please.

MS. RAITT: Okay. So this is a question from Jairam Gopal. "How significant is the quantity of natural gas consumed by refineries compared to total gas consumed in California for all sectors?"

MS. ELDER: Hi, Jairam.

The forecast of natural gas consumption for the refineries is about 500 MMcf per day. So contrast that with average demand say of 2.8, 2,800 MMcf per day, on an average day. And maybe you're at -- I think SoCalGas is forecasted one 35 peak day is something like 5.1 Bcf or 5,100 MMcf. So on a peak day it's roughly maybe 10 percent of SoCal's overall throughput.

CHAIR WEISENMILLER: I think the other way to look at it is that in the summertime, the variation obviously between summer and winter when it's hotter in summer, but generally in the summertime it's about 60 percent of the requirements down here are for power plants. And in the wintertime about 60 percent are for core customers.

MS. RAITT: More questions, anyone?

(No audible response.)

COMMISSIONER DOUGLAS: All right. Well, those were great technical questions, thanks.

And thank you to both of our panelists, so Heather we can move on.

MS. RAITT: Great, thank you.

So next is Greg Reisinger from the California Public Utilities Commission.

MR. REISINGER: Hello, Commissioners. So I'm Greg Reisinger from the California Public Utilities Commission and I work in the natural gas section of the Energy Division.

What I'd like to do is talk a little bit about the curtailment process that currently is approved and in place at SoCalGas. And then talk through pending changes, how those pending changes will affect the refineries. And what the actual plan will be for 2016.

One thing that I think merits noting is that Katie mentioned the Action Plan. And one of the mitigation measures in the Action Plan was to put in what we call tighter balancing rules. And in effect, create incentives for customers to bring in supply close to what is forecast to be burned. So that has been done in a little different method than balancing. It's been done through tightening up what's called an operational flow order, which essentially creates incentives. And sends messages to the market that you need to bring in more gas to meet expected demand.

And the reason I mention that is the curtailment process, to me at least, is really just an extension of that operational flow process. There's a number of steps that you go through and then the next step is curtailment. And it's just a continuation of that process that we started with the operational flow orders. If you go to the next step? No, I think we missed a slide, yeah.

So if you look at the recent history of curtailments what gets flagged sometimes, and in fact in the proceeding around curtailments, there was a protest that noted the significant number of curtailments that are being experienced on the SoCalGas system. If you dig a little bit deeper what you find is that in 2015, when there was this big jump up to 15 curtailments called in that year, most of those -- 14 of them -- were really safety-related curtailments that were planned.

They were localized and typically well-coordinated with the customers. Customers knew well in advance that there was going to be a curtailment, so that number can be misleading. But what we're really looking at is the number 15, the one that fell outside of that. And that was a curtailment that happened as a result of a number of conditions overlaying on June 30th and July 1st of last year.

It's sort of a notable exception to the safety-related ones. And it occurred, because of a number of two safety-related outages, limited hydroelectricity generation. A series of things that overlaid that created this curtailment, which by the way never did ultimately require that electric load be curtailed.

That said that's the kind of risk that we're looking at this year and that the curtailment process needs to address. So the next slide.

If we look at the current rules I think that the best way to say it is that they're complex and out of date. The current curtailment rule, which is Gas Rule 23 has nine priority service groups. It's got firm and interruptible distinctions and this complex system for firm intrastate service curtailment procedure. And so much so, that it includes things like lotteries that could potentially result in somebody being curtailed in an area in the system, which where the benefits of that reduced demand can't impact where the problem is.

So it really does not operate well as it's designed, for our current gas and electric market place.

So next slide, please?

However, one of the things after eight pages of a very complex layout of what that plan is -- of what that rule is -- it does provide considerable flexibility. In the case of an emergency curtailment or a localized curtailment SoCalGas has significant flexibility in deciding who gets curtailed in what amounts, and where those curtailments will be made.

And that is of potential significant benefit for this summer. Next slide please.

If you look at what's been proposed now SoCalGas filed an application. It's A. 15-06-020 and it really simplified the rules. Basically it recognizes the change in the gas and electric markets. It does focus on electric generation, but it curtails it down to a set level first and then moves on. It then hits large commercial and industrial customers and then the three categories of core customers: so large, small, and residential customers.

There was a response to that on the part of the -- and there's been a settlement agreement that's been proposed and is currently working its way through the system.

And in response to the application the generators came back and said, "The percent that you're going to first curtail electric generators is not appropriate for the two different seasons: the winter season and the summer season." So they asked for an adjustment for that.

And the independent shippers on behalf of refiners came back and said, "We need to look at what can be done to recognize the safety and operating risk when you reduce a refiner's supply?" Next slide, thank you.

So the proposed settlement agreement kept most, essentially all of the SoCalGas application as it was proposed, but it modifies the electric generation to be curtailed based on summer and winter. And it carves out refineries establishing a minimum usage requirement that'll be maintained, so a supply will be maintained to cover those. And it carves them out of other commercial and industrial users. Next slide?

So more specifically if you just walk through the -- I think we skipped one again.

MS. RAITT: I'm sorry.

MR. REISINGER: No, maybe not. Let's go ahead. I'm sorry.

Just to walk through what the new orders are, and we'll move quickly through this, is it changed it -- basically it says that electric generation forecast to be operating is effective to remain on, but others currently not operating will be curtailed. Up to 40 percent in the summer, 60 percent in the winter, is the second step for

EG. Next slide, please?

And for refiners once up to 100 percent of the non-EG noncore and noncore cogen, on a pro-rata basis, except for pre-established refinery minimums. So in that sense the refineries are protected before you go to the next step, which is Step 4 in the curtailment process, which would curtail them all the way up to 100 percent in the remainder of EG.

So it sort of inserts a step that gives some additional protection to the refineries to meet this minimum usage requirement that allows them to operate on a more safe basis. And it recognizes that unlike what one might think, these are complex operations that you can't just throw the switch and turn them back on and they're operating right away. It takes frequently days, and sometimes can be weeks, to bring a refinery back up. And in addition there could be damage done to the refinery if they're shut down. Next slide?

And then the final three steps are large core, small core non-residential, and residential. Next slide?

So the status of that motion is it's awaiting a proposed preliminary decision, proposed decision. It'll be implemented 90 days after approval. And it wouldn't be likely that that would happen until September. If things were to move quickly, it might happen in September, but...

and if we hit the next slide?

Because of that flexibility in Rule 23, SoCalGas can use emergency curtailments as necessary. And their plan is to follow the general intent of the proposed settlement agreement. So that in speaking to them, they're going to act and behave as much as possible as if that settlement agreement were in place, which fits fine under the use of an emergency curtailment.

And SoCalGas has also indicated that they're currently working with the refiners to establish those minimum requirements. That is the sort of one hiccup is they aren't yet established and that's going to be a back and forth process to determine what is the actual required minimum that's agreeable to both parties?

And final slide, I think ends it for me, so questions?

CHAIR WEISENMILLER: Yeah, a couple of questions.

First was -- obviously one of the items of the Action Plan was to look at the -- well okay so SoCalGas typically does maintenance in the summer, because peaks are in the winter. And there's also the overlay of the various safety tests that need to be done. So one of the early Action Plan items was to determine what their maintenance plans were for the summer. And then to try to make that difficult decision, particularly for the safety questions, you know thinking of what we could do in terms of possible deferral of actions.

How far along is the PUC on that part of the Action Plan?

MR. REISINGER: With regard to the safety, and I don't have the exact date, I can picture on a page. But the SED, the Safety Division, has been going through an analysis.

My initial understanding was that there's not a lot that can be deferred from a safety standpoint. But they'll have a report out -- I want to say within 30 days --- that addresses that specifically. They have gone through and looked at these projects, but there's limited ones from a safety standpoint.

I do know there has been good coordination on the non-safety maintenance.

CHAIR WEISENMILLER: Yeah. So it will be interesting to try to understand -- just looking at your chart where most of the curtailments were from the safety work.

MR. REISINGER: Yeah.

CHAIR WEISENMILLER: And then to the extent we're trying to figure out the refinery element of this, trying to get some sense of the planned safety work and how that might impact refineries.

MR. REISINGER: One comment, backtracking on those localized curtailments. Many of those were very localized. I mean, you're talking over blocks in a city and so there's a set of them that are almost inconsequential.

CHAIR WEISENMILLER: Okay.

MR. REISINGER: Historically.

CHAIR WEISENMILLER: Okay. The other one is my recollection of, I think it was Rule 23, but it might be off -- there were basically pretty clear steps in the context that, "Do whatever you can, so you don't curtail core." So if you have to confiscate flowing gas, if you have to confiscate gas in storage, just do whatever you have to do.

Is that still embedded in the framework?

MR. REISINGER: I think that it ultimately is and I think SoCalGas would say that's their core obligation. No pun intended.

What this does though, is it gives a much more rational basis before you would ever get to that situation of having to curtail core. It's a much more rationalized process.

It also -- and I didn't mention -- does separate this into 10 zones, so that it does away with this issue where you're curtailing somebody over here and it can't impact where the problem is over here.

CHAIR WEISENMILLER: Well, that's good to know.

MR. REISGINER: This makes it a little more micro. And you look at addressing the issue of where it is.

CHAIR WEISENMILLER: Yeah. And also, obviously President Picker and I both channel each other pretty well. And I assume one of the issues that are noted in the refinery part is the safety implications at the refinery itself in having sudden shutdowns.

MR. REISINGER: Yeah. And I didn't read the quote, but specifically that minimum requirement is to address and recognizes the safety issues with the shut-down.

CHAIR WEISENMILLER: That's great. And as I said I think it's one of the things, which we're really trying to embed in the PUC culture is considerations of safety.

MR. REISINGER: Yes.

CHAIR WEISENMILLER: Great. Thank you.

MR. REISINGER: You're welcome.

Are there questions?

COMMISSIONER SCOTT: I have another question for you back on the status of the proposed settlement motion.

MR. REISINGER: Uh-huh?

COMMISSIONER SCOTT: So you mentioned that it's awaiting a proposed decision and that it would be implemented in about 90 days after approval.

Are the public components, like the public workshops and other discussions that you've had, are those completed? And now it's just kind of waiting for this process or will there be other opportunities for input?

MR. REISINGER: Well, yes. The settlement agreement is literally just waiting the decision. And there won't be anything -- the 90 days is part of the settlement agreement. That was put in by parties. (phonetic)

COMMISSIONER SCOTT: I see. Okay. Thanks.

MR. REISINGER: Yep.

COMMISSIONER DOUGLAS: All right. Thanks. I think that's all the questions from the dais.

Are there any questions from the audience, technical or clarifying questions or the WebEx?

MS. RAITT: Not that I know of.

COMMISSIONER DOUGLAS: It does not look like it, so thank you very much.

MR. REISINGER: You're welcome, thank you.

COMMISSIONER DOUGLAS: We'll go on to the next speaker.

MS. RAITT: So, thank you.

So next is Dave Hackett from Stillwater

Associates.

MR. HACKETT: Good morning, Commissioners. I'm Dave Hackett. I'm the President of Stillwater Associates.

Stillwater is a transportation energy consulting company that focuses on engineering logistics and markets and regulations for the downstream petroleum business. So our practice areas are focused on the supply chain of oil. And in large measure people hire us to explain how gas gets to a gas station.

And so I thought we'd talk about that some today in the next slide, please? That's the intro. Go to the next one.

Our agenda, we've talked about product flows on the West Coast -- Gordon touched on that -- and then get into the gasoline supply in Southern California. And then talk about refineries and natural gas and then as well fuel supply and electricity and some then conclusions. Next slide?

So as Gordon mentioned the refining centers are in the Pacific Northwest and the San Francisco Bay Area and in Los Angeles. And there are no interconnecting pipelines. The markets are -- there's market movement between, but all by tanker and barge. There are no pipelines that serve this market from any other areas. So these are essentially three refining enclaves. Next slide.

Focusing on Southern California -- and you saw from Gordon's slide -- that the refineries are here in the South Bay Area largely. And they produce gasoline, jet fuel, and diesel and then those products are distributed -- much of it is distributed locally.

There are company-owned pipelines that go to distribution terminals where the trucks are loaded. And that truck is the one that goes to the gas station, but this market also supplies -- and so those trucks goes far north and west as Santa Barbara or into Santa Maria -- and then up to the high desert.

The KinderMorgan Pipeline supplies markets in San Diego, in the Inland Empire, sort of centered around Colton. And then their pipelines go up to Las Vegas and then further east all the way to Phoenix.

So this distribution system supplies all of Southern California for gasoline, most of Las Vegas, and probably about 20 percent of Phoenix's demand. So it's an interstate complex, next slide? And again, the next slide.

So, remote and isolated -- I mean it doesn't feel like we're remote and isolated -- but as far as the world is concerned I think we are. And so when production is curtailed, the additional supply has got to come from someplace. And we've seen the impact of that, I think, over the years of primarily when unexpected refinery maintenance happens, if there's a power failure or some other kind of problem. I think the latest one was at Torrance Exxon, the Exxon Mobil refinery at Torrance that had a problem in February of '15 that still is not quite rectified. And we'll see the impact of the pricing here in a moment on that, next slide.

So here I tried to look at supply and demand. I'll confess I cheated a little bit on this graph. It starts at 94 percent. But what I wanted to point out is that normally -- and we'll see what normal looks like in just a moment -- normally there's about a 4 percent shortfall. And it's made up from the regional refineries, which not only the Bay Area and Pacific Northwest, but also from refineries in Canada that supply fuel into -- or gasoline and gasoline-blended components into Southern California.

And so when there's unplanned maintenance then the additional supplies come from someplace. It may be drawn from inventories that have been built up or the other regional refineries may have the flexibility to produce more California-specific gasoline and send that down. Or it has to come from long distance. Next slide.

And here is somewhat of a complex slide, but basically it's designed to show the volatility in the gasoline market.

This is the California Energy Commission data. I think I got this from one of Gordon's slides. And in the period here is from August of '14 to January of '16. And you can see in the first part of this period that these numbers of his basically represents the difference between the world market and the California market.

That's the objective of this exercise.

And you can see that those numbers move around some, but they're not wildly volatile, as it got to be starting about the middle of February with the problem that Exxon Mobile Torrance had with its gasoline-making equipment.

And then there were other problems in Southern California in '15. It was a very volatile year, most of this due to refining problems.

In this illustration the blue line is the Los Angeles spot market, the wholesale market. And the red line is the San Francisco Bay market. And generally they are parallel. But you can see that there are points where those markets diverged, where L.A. got to be a lot higher than the Bay when it came to the reference to the rest of the world.

And so that illustrates this issue of L.A.s different, and it's generally short of supply. Whereas the Bay Area -- we haven't talked about that -- but generally the Bay Area is long. Next slide.

In this slide, these bar graphs illustrate the volume of gasoline imported into California, into Southern California from '14 to '16. And these are monthly data from the Energy Information Administration.

And what this illustrates is that the oil industry responded strongly to the price signals that were created, that we talked about a moment ago, and brought gasoline in from around the world. Written there in very small text it's Canada, Korea, China, the United Kingdom, Taiwan, Russia and Japan and I think some others.

And so it takes a strong price signal in order to get refiners from around the world to pay attention to what's going on here and take the risk to bring the product to California. Next slide.

Okay, let's talk about natural gas. Next slide.

Gordon did a really good job I think with this ad hoc survey that they put together in less than a week. We actually have some numbers to look at about how much natural gas is consumed by the refineries and where in the refinery that it's consumed and so this pretty much just supports what Gordon had to say. But there's the basic refining processes, which you're boiling oil and cracking it. The cleanup of the oil that takes the contaminants out, that's the hydrogen manufacturing. The refineries can't make California's ultra-clean fuel without hydrogen.

And the fuel for the cogeneration plants, which basically provide power and steam for the refinery. And the excess is sold to the Grid. Next slide.

So I asked my colleagues, many of whom worked in refineries here in the Los Angeles Basin, what would happen if natural gas was curtailed. So I have a bit of history here.

Long ago, the refineries could switch to running -- burning low sulfur fuel oil. But of course there's a fair amount of criteria pollution that goes with it, not to mention greenhouse gases. And so they used to be able to switch to that low sulfur fuel oil, but they don't have that capability any more. They don't low sulfur fuel oil. And they don't have the equipment for that.

They do have some flexibility to switch to other gasses that are produced, primarily propane and butane, but as we discussed this issue -- what my colleagues would call -- is some process units have the capability to be dual fueled and others do not.

And I think that -- yeah, let's go to the next slide. No, let's back up. I'm sorry.

One thing that's clear is that all of the process units, the burners and heaters that have been put in recently, meet the highest standards of emissions reduction. And so they're all running on natural gas. They may not have the plumbing it takes to be able to switch to propane, but I think that we'll need to ask the refiners for their view on that.

Okay, next slide and the next one.

So one thing that is clear is that good quality electricity is vital to the fuel production distribution; they're large consumers of electricity. Their pumps and compressors are electrically-powered and they run continuously.

These places run 24-7, 365 if they can do that. They really don't want to shut them down unless they have to. And we've seen demonstrated the problems when the electric supply is disrupted. The one that comes most to mind is the one at Exxon Mobile Torrance, in October of 2012, which caused a big price spike. And that actually I think was the genesis of the Petroleum Market Advisory Committee. That was the event that brought us together there.

And then also as well, the logistics system requires electricity to deliver the fuel that pump the gasoline away from the refinery either to the propriety distribution terminal that Chevron, or Exxon, or Shell might have. Those same pumps pump to the KinderMorgan System. It's the KinderMorgan System that distributes the product to the rest of the state. That's true in Northern California as well as in Southern California.

And I'm reminded that probably a key event in the electricity crisis of 15 or 16 years ago was KinderMorgan couldn't get electricity for its pump station up in Northern California. And the gas stations were running out of gas and the refineries were filling up with product, because they were curtailed. The next slide and the next one.

So curtailment of natural gas and/or electricity may result in reduced refining operations and lower product supply. And in the past that's caused price excursions.

And so to some degree or other you're trading natural gas power supply problem for a broader transportation fuel issue. Certainly reducing natural gas refineries reduce cogeneration and which I'm told -- I don't know anything about it really -- but my colleague tells me that that's efficient in-basin supply of electricity, which is useful as far as the Grid's concerned.

And then listening to the Chairman's questions about his concern that really he's more concerned about the winter than the summer -- summer's bad enough, but the winter's really concerning.

And so it may be worth having a conversation with the interested parties about what flexibility refiners have, in order to do some sort of substituting, given from now until the winter time to figure it out.

CHAIR WEISENMILLER: Yeah.

MR. HACKETT: And that concludes my talk. Thank you.

CHAIR WEISENMILLER: Great.

MS. RAITT: Questions?

COMMISSIONER DOUGLAS: I have one question, which is that you talked about how there's overall generally a 4 percent higher demand from local supply in the Southern California area.

And so there's some amount of excess capacity, whether that's the Bay Area and some other sources to meet that demand. Is that generally something that's played out sort of evenly over the year or are there seasonal differences in the demand-supply picture?

And I'm asking about in part, because we're looking at more sort of real-time potential events or issues as opposed to a longer-term supply/demand issue. So it kind of gets to the question of how much resilience there is in the system for the short-term disturbances.

MR. HACKETT: Let's see. The longer term is easier to address, because the refineries like any other large plant, have a maintenance cycle. And so every three-to-five years everything in the place gets taken down and fixed up and brought back up again.

And given enough time the refiners can plan around that in order to accommodate whatever it is they need to accommodate. In fact, we may hear a story about that specifically as far as this is concerned.

But in the short term I think I would defer to what the refiners had to say about that. I don't think I've got any good short-term answers.

COMMISSIONER DOUGLAS: All right, thanks.

CHAIR WEISENMILLER: All right, actually excuse me, I was just going to ask the question, another issue (indiscernible) is basically jet fuel at LAX. Where's that coming from and how much -- again are we going to have a pipeline issue getting the jet fuel in?

MR. HACKETT: So the --

CHAIR WEISENMILLER: Or other airports, obviously?

MR. HACKETT: Yes. And so the bulk of jet fuel is locally produced although a fair amount does come in from abroad. And the airlines have the ability to import jet fuel.

And so those import flows are actually fairly well-established, because they're happening on a regular basis. There is a regular movement of jet fuel tankers from Asia, from Korea, or Japan or Singapore, coming into California. It's a normal practice.

And I would say what we realized in '15 when Exxon Mobile went down there wasn't a regular flow of gasoline coming from Asia, like there is jet fuel. And so I'm less concerned about jet fuel than I am about gasoline.

COMMISSIONER DOUGLAS: All right, thank you.

Any clarifying or technical questions from the audience?

(No audible response.)

MS. RAITT: No.

COMMISSIONER DOUGLAS: All right, well thank you very much.

MR. HACKETT: You're welcome.

MS. RAITT: Great. So next is John T. Hansen from the Western States Petroleum Association Antitrust Counsel.

MR. HANSEN: Thank you.

Mr. Chairman and Commissioners, good morning, my name is John Hansen and I am the Antitrust Counsel for Western States Petroleum Association. I promise to be very brief.

Two members of WSPA will be participating in the panel discussion, which I believe is the next item on your agenda. Because these two companies, Phillips 66 and

Tesoro, are competitors the panel must be conducted with the antitrust laws in mind. It is appropriate and lawful under the antitrust laws for competitors to meet and discuss matters related to ongoing government planning and potential rulemaking. But WSPA has certain policies applicable to this panel that its member companies will be following this morning.

Specifically, these companies will avoid any discussion of past, present, or future prices or any aspect thereof, territories, costs or any aspect thereof, sales or anticipated sales results, identification of customers, inventories -- both types of products and inventory and inventory levels -- production levels or capacities, planned or anticipated refinery shutdowns, distribution of marketing strategies, or any other element of competition including compliance plans of a particular refinery.

In connection with today's workshop, as we have heard from Mr. Schremp, the CEC has conducted a confidential survey of Southern California refiners under PIIRA, the Petroleum Industry Information Reporting Act, to obtain recent information regarding the use of natural gas and other related fuels in the refiners' facilities.

In addition, the confidential survey contained questions regarding potential operational flexibility. And as also you heard from Mr. Schremp, the WSPA member companies have cooperated fully in providing the CEC with the requested confidential business proprietary information, all for the purpose of assisting this Commission, assess the potential impacts on transportation, fuel production and availability that could result from any natural gas curtailment events during the summer.

I will be the in the audience for the panel discussion. And although I seriously doubt it will be necessary, if at any time the discussion should stray into a sensitive area, I will interrupt briefly and direct the discussion back to the issues on the agenda.

That's all I have to say and thank you very much for your attention. I appreciate it.

COMMISSIONER DOUGLAS: All right, thank you.

MR. HANSEN: I doubt you'll have questions. Thanks.

CHAIR WEISENMILLER: I would just make the observation that we appreciate the data that we get from the industry. And understand because of the issues you've just raised, that we are treating that information as confidential in a sensitive fashion.

MR. HANSEN: Yes, we understand and appreciate that of course. Thank you, so much.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Great, thank you.

So next we have a discussion panel on curtailment notification needs and possible plans to address natural gas and electricity disruptions. And I'd like to ask our panelists to come up to the table: Gordon Schremp, Jolie Rhinehart, Joshua Valdez and Dave Hackett.

(Pause to set up Panel.)

MR. SCHREMP: Well, good morning still. This is Gordon Schremp again. What was good once is going to be even better the second time, so thank you for all being here again and I especially thank the panel members for agreeing to participate in the panel.

I know I always learn from speaking to people in the industry that do the operations, that have more a sense of knowledge base than I or other technical staff. So we greatly appreciate the opportunity to ask questions of the panel members. And we certainly really appreciate all of the insight and factual information you've been able to provide us as we work through this process and analysis. So thank you again for being here.

So I thought we'd start with doing some introductions. We'll go from the closest to -- if you'd please introduce yourself, sort of what your duties are with your organization, and any other opening points you'd like to make about the panel discussion we're about to have.

MR. VALDEZ: All right, so my name's Joshua Valdez. I've been in refining for 12 years. I've done operations, I've done engineering. I'm currently the Executive Director of Watson Cogeneration Unit. And I'm going to defer my opening remarks to Jolie, and then I'll come chime in later.

MR. HACKETT: Good. And I'm Dave Hackett with Stillwater Associates.

MS. RHINEHART: Good morning, my name is Jolie Rhinehart. And I'd like to start by thanking you for conducting this educational workshop to help us better understand the implications that the Aliso Canyon issue poses to oil refining in Southern California and specifically for allowing me to participate in this important discussion.

I am a chemical engineer and have been working in oil refineries for the past 18 years. And specifically I've worked in three different oil refineries on both the East and West Coasts. I'm currently the Operations Manager at the Phillips 66 Wilmington, California refinery and am responsible for the safe, environmentally sound, and reliable operation of the refinery.

The safety of the personnel and the surrounding community is of paramount concern to me in my current role. I'm appreciative of being involved in this important discussion regarding Aliso Canyon as steady supplies of natural gas and electricity are necessary and integral to the safe and reliable operation of oil refineries. As such, we are critically concerned about the reliability of energy supplies that are threatened by the current circumstances surrounding the Aliso Canyon.

Oil refineries are large, very complex and significant users, of natural gas and electricity. Oil refineries are operated to produce the transportation fuels crucial to the continued quality of life that we have in California. Oil refineries run in a steady state fashion. Specifically due to the significant complexity of how refineries operate we are neither agile nor able to quickly modify operation without substantial risks and certain impacts to transportation fuels production.

The only time we make quick operational changes is during emergency responses. And during these emergency operations we are at higher safety and environmental risk.

In the unfortunate event of a loss of power, power disruption, or reduction in natural gas availability, emergency response will ensue and the refinery units must be shut down in an emergency manner. These events result in significant environmental impacts.

In addition, emergency responses put significant risk on our people, the community, the refinery equipment, and can take a week or longer to return to normal operations and resume production of transportation fuels.

The bottom line, a quick curtailment of natural gas or electricity to an oil refinery will result in a long recovery, higher safety risk to refinery personnel, community impacts, and negative environmental impacts. On a planned or nonemergency basis, to shut down a refinery or portion of refinery units typically takes five-to-seven days. And these planned shutdowns are scheduled up to five years ahead of time.

Extensive, proactive planning is required when shutting down refinery units due to the complexity of the refinery equipment. And these plans include measures to ensure personnel are proactively prepared, there is additional staffing, additional refinery supervision and engineering oversight, and measures are put in place to minimize the environmental impacts. In addition, these plans ensure transportation fuel logistics are planned, so there are no shortages.

We've been operating refineries in Southern California for nearly 100 years. And the cost of electricity and natural gas are a very significant part of our operating costs. Many energy reduction projects have been implemented to minimize these energy costs throughout those years.

In addition, several of the refineries in Southern California have cogeneration units that will be impacted in the event there is a natural gas curtailment or loss of power and that will result in higher demand from LADWP.

Since the energy and natural gas costs are such a significant portion of our operating expenses we have a daily focus on adjusting operation to minimize both electricity and natural gas usage. As such, curtailments are extremely difficult and also very dependent on the refinery operation at that time.

Our flexibility to reduce natural gas usage is very limited at oil refineries in addition, because we have other constraints including equipment that is specifically designed to only burn natural gas. As was mentioned earlier this includes a portion of our cogeneration feed, our hydrogen plant feeds, but we have burners that are specifically designed only to burn the very clean natural gas.

In addition, we have environmental restrictions were several of our heaters are only permitted to burn natural gas. For these, natural gas curtailment is only possible with unit shutdowns that will impact transportation fuels production.

Just as the Public Utilities Commission, an

California independent system operator have warned, the state can only mitigate some of the risk. Not eliminate the risks altogether. Therefore the most effective solution to Aliso Canyon will require that all stakeholders do their part to mitigate the material risks of natural gas and electric service disruption, while safely and incrementally returning Aliso Canyon to full operation. Thank you.

MR. SCHREMP: Thank you, Jolie.

All right, well I'll kick things off. I know this -- oh I'm sorry, Josh.

MR. VALDEZ: Yeah, I deferred. I had deferred.

MR. SCHREMP: Oh, I'm sorry. You gave up your time. (Chuckles.)

MR. VALDEZ: So I'm going to make sure that I try not to repeat the things that Jolie said, because I think we support that as well. But I'll second her and I appreciate the fact that the CEC has taken the time to listen to us to kind of understand, or try to understand what the impacts are going to be from a natural gas or a core electrical curtailment.

Refineries are complex just like Jolie said. They run at extremely high pressures, extremely high temperatures, they use highly reactive catalysts. These are things that are very dangerous in nature, and so these units and these refineries are built to operate at a steady state. And so any time you introduce change into them you introduce risk and not only risk to the people on the ground, the operations individuals, but you introduce to the equipment, to the market supply of hydrocarbon or fuel to Southern California, as well as to the community. And so doing what we can to keep that steady state is extremely important.

As has been stated, I mean refineries' equipment takes hours to days to start up and shut down safely, planning for outages anywhere between months to years to do.

And although refineries may be on a critical infrastructure list, from a curtailment standpoint, there are a number of ancillary plants that support refineries as well whether that's hydrogen production, whether that's sulfur recovery, whether that's logistics, whether that's utilities, nitrogen or oxygen. Those locations are not on that protected list, so whether the refinery sees that or the ancillary plants see that the impact is very similar.

At the same time from a natural gas standpoint natural gas comes into a very big role, plays a very big role in refineries, in particular around safety systems, pilot gas and heaters, flare gas, burner tips, your tank blanket gas -- all of these things that are extremely important, both to the refinery itself and local communities, who rely on natural gas heavily.

Because of the constant pressure, the security that you have around natural gas, the content, and because they are safety systems you want to have some type of reliability in that. And so it's very important to understand that as well as the fact that some refineries have cogens. And so not only will they be impacted from a natural gas and electric standpoint, but also from a high-pressure steam standpoint.

And so one of the things that we're concerned with or that refineries are concerned with, with congens, is the fact that you do lose that high-pressure steam, which you use to drive processes, equipment, as well as to process fuels. And so the goal here is to make sure we communicate what our concerns are and understand what the potential mitigations are there to limit the impact to the community, to the refinery, as well as to the local fuel market.

MR. SCHREMP: Thank you, Josh.

Yeah, I know I mentioned on one of my slides, about other utilities and processes outside the refinery gate that the industry depends on. So I think this is certainly an area that it would be helpful to obtain some additional information from the refiners.

So I'll just give you the heads up it might be circling back to you, because as people have made observations in the past about me, like more data is good, guilty as charged. So we are interested in better understanding, if there's some ancillary services we do not -- aren't fully aware of that are critical to operations. And that may see some sort of impact of curtailment either to loss of electricity, rotating outages, or natural gas feed to their operations.

So thank you for that Josh.

And thank you Jolie for your introductory remarks.

So I'll kick it off. I'll back up just a little bit and I know this is the -- the primary focus is natural gas curtailment to refiners and potential impacts on conservation of fuel supply. But certainly as Katie was talking about there could be -- what the first call is going to be on electricity producers and you could some rotating outages that occur.

We understand there's an exemption list for SoCal Edison back from 2001. LADWP doesn't have really a public list like that, so we're not fully aware -- or at least I'm not, maybe other people are in the Commission -- of who might be on that list and where the order is. But even so knowing those exemptions exist, it is still possible that those could be touched on if the curtailment is so great in the system.

So I wanted to go back to what Jolie said earlier about just to clarify. So we've seen loss of electricity in the Basin periodically over the years. And that from our understanding it takes -- a refinery goes down, because they have to initiate emergency shutdown procedures. So I just wanted to verify, so you mentioned maybe up to five to seven days to recover.

Is it from some event like a loss of electricity that's sudden to a facility? It can take those many days to come back and sort of why is that the case?

MS. RHINEHART: Yes. One of the reasons why, there's a very distinct difference between an emergency shutdown and a planned shutdown, and that as Joshua mentioned we have highly reactive catalysts.

So if you were going to plan a shutdown, you could slowly reduce your feed rate and then sweep the hydrocarbon off of your catalysts. And that takes time, these are huge vessels filled with catalysts. The hydrocarbon is in every open spot in that unit. And that can take multiple days.

And so when you have an emergency shutdown, you're essentially just shutting the whole piece down on its own. And so when I talk about emergency shutdowns and loss of power specifically, it's just like pulling the plug out versus maybe rebooting your computer, except our planned shutdown takes multiple, multiple days.

So when you have an emergency shutdown your catalyst systems are left filled with hydrocarbon. You can have high-temperature situations. And so we evacuate the units as safely as we can. But what can happen is your piping can get plugged with heavy hydrocarbons. You can have multiple flow issues. You can deactivate your catalyst. If you lose hydrogen and you still have hydrocarbon on there, that can result in really high temperature coking, like almost an asphalt creation that you may have to go into and chip out the catalyst. That would take well more than seven days to recover from.

In units such as a coker if you disrupt the coker during operation, you will have incomplete coke and soft coke causes all kinds of pluggage and disruption. So I hope I'm answering the question.

But if you plan it you slowly reduce the rate, you stage the equipment, you can follow your procedure. The emergency shutdown is pull the plug and figure out where you have issues. You can damage equipment. You can have bowing of your catalyst trays and distribution headers. And essentially the emergency shutdowns are just to get it into a safe state and then you have to figure out how to dig out of that hole that you've created.

COMMISSIONER DOUGLAS: So just a quick follow-up question, when you talk about planned versus emergency, how much advanced warning do you need to have for you to think of this as planned or a potential shutdown as planned?

MS. RHINEHART: Yeah, it depends. There's no simple answer, but I mean about a week is a decent timeframe to give in my opinion.

COMMISSIONER DOUGLAS: Okay. Thanks.

MR. SCHREMP: So Jolie so the question the Commissioner just asked, so that was for a natural gas curtailment call. And so that's a good segue into sort of the next area I wanted to investigate, is curtailment calls.

Yes, I think the Chairman was talking earlier about expected heat event that's going to cause a demand increase and concern for early next week, can't precisely predict that unfortunately. But so basically the more lead time you have allows you, a refiner, to better position to take a reduction in natural gas from a natural curtailment call. Is that an accurate statement?

MS. RHINEHART: Well, I would rephrase it a little bit only to say the sooner that we know the better. Because there is, depending on the configuration of the plant and what plant equipment we have, we can certainly communicate what the potential is for us to -- as Dave talked about earlier -- to put butane or propane into fuel to offset the natural gas that we can.

And again it just depends on how the plant is running. If we have a planned outage of a big hydrogen user we have less flexibility to reduce natural gas than if the plant is in full steady state operation.

Does that answer the question?

It just depends. In the communication that I see is the more advanced notice if you talk to each refinery to understand how the refinery is running and the communication of our configuration, how close we are to our minimum, the better I would assume, so we know where the whole system is.

MR. SCHREMP: Okay. Thank you, that's helpful.

And I'll turn to Josh. I know because of your company's operations being, maybe I say a bit different, because you have a great deal of cogeneration capability that's -- in fact excess sells to the local grid -- is there sort of a different sort of curtailment lead time response that you might have for say cogeneration operations? Because they're certainly maybe not as complex as Jolie was explaining about all the other different types of process units in a refinery in general.

So there were some differences for that type of operation?

MR. VALDEZ: So refineries with cogens, a natural gas curtailment -- the longest lead time from a knowledge standpoint is still extremely important, because like Jolie said from a refinery standpoint you have impacts from natural gas usage. But when you come to a cogen if you have natural gas curtailment, and you do not have the flexibility to produce the alternate fuels in order to power your cogen, then units start to come within a cogen facility. At which point you start losing critical items like steam.

Steam is extremely important in a refinery, high-pressure steam. And so losing that high-pressure steam can cause just as many upsets as -- well won't cause as many, but causes significant upsets very similar to a natural gas outage, in the actual refinery itself.

MR. SCHREMP: So the cogen facility itself can, I guess, adapt to a shorter-term curtailment call in terms of safely taking that kind of unit down.

But as you point out, if I'm hearing you right, the loss of high-pressure steam to the refinery now sort of cascades over to impacts on other process units that cause some of the problems that Jolie was describing earlier. Is that fair?

MR. VALDEZ: It is, but at the same time a cogen facility doesn't necessarily have the ability to respond, because it's dependent on the refinery. And so some of the things that Jolie has stated around equipment being out of service, things of that nature, crude availability, the dissolution profile of that crude, may or may not provide enough gas to be fueled in order to support the cogen.

So the cogen itself doesn't control that, the refinery does. And they're 100 percent dependent on the refinery.

CHAIR WEISENMILLER: Yeah, I was going to say we actually had the staff do a fairly detailed analysis of the refinery cogen projects in the sense of air quality and all the other constraints. And the answer is that at one point PG&E just assumed you could flip them on and off just for the hell of it. And the answer is you can't once you look at the permitting requirements and everything else. It's a pretty complicated topic.

I testified some before the ISO on that topic based upon the staff analysis.

MR. VALDEZ: Thank you.

CHAIR WEISENMILLER: Go ahead, do you have a question?

MR. REISINGER: I just had a comment --

CHAIR WEISENMILLER: Well, come up to the mic please?

(Pause to situate microphone.)

MR. REISINGER: Hi, Greg Reisinger from the CPUC. And in discussing the new curtailment rules, the proposed curtailment rules, I refer to the carve-out generally to refineries.

But just for clarification I want to state that it covers refineries including cogeneration and ancillary facilities. So to the extent that that's helpful information, that was anticipated that these ancillary facilities in cogen are a critical part of the process.

MR. SCHREMP: And Greg, if I may, when you say in ancillary facilities is that both within the "refinery gate" as well as outside that may be a different third-party company. Is it both of those examples?

MR. REISINGER: It was not defined. I don't know at the level that it's stated currently whether that's inside or outside. You know, whether it includes facilities outside.

But at least from the general reading of it, it anticipates this issue that there is cogen and ancillary facilities that have to be considered. And that are considered in the curtailment process.

MR. SCHREMP: Thank you.

And Josh, you have a comment on that?

MR. VALDEZ: Yeah, so the current curtailment policy that's out there, or the one that is waiting to be implemented, allows the consumers of natural gas to have flexibility as far as where they curtail.

And so one of the things that are still under question is the flexibility, so if the refinery was called to curtail then they would have to curtail. And they don't a lot of flexibility to curtail. So they would reach out to some of their other facilities that are within their span of control to ask them to go ahead and curtail to meet the overall demand.

And that flexibility is important, so when we talk about cogen being protected at that top tier or the third tier down on the curtailment procedure or the process, it's really important that we understand that that flexibility for refineries are over end noncore users to be able to kind of play the game, the shell game, and shuffle around their natural gas curtailment to meet the overall demand.

But to choose what facility to do that is really important.

MR. SCHREMP: And Josh, just to be clear, so is that facilities that you have direct control over or you have business relations with?

MR. VALDEZ: So it's only facilities that are directly under your span of control, so you wouldn't be able to play it if it was an Air Products facility or a Praxair facility. It's only within your span of control.

MR. SCHREMP: Okay. Thank you.

I did want to pursue --

CHAIR WEISENMILLER: Actually, I have a couple of questions, so let's sort of hit some additional ones.

One, is in terms of impacts how different is electric curtailment versus a gas curtailment on refinery operations?

MS. RHINEHART: I feel like every comment that I have is going to start with "it depends."

CHAIR WEISENMILLER: I realize that, yeah.

MS. RHINEHART: I usually would -- I feel like I think when I hear electric curtailment, is that we're going to lose electricity or have a power disruption. And that is absolutely the worst.

But a natural gas curtailment, it just depends on the level. If the question is to go to the main reads (phonetic) that we supplied to SoCalGas as part of this new discussion, I feel like that is certainly better than a loss of power. A loss of power is game over and we're down below what our minimum is.

Again it just varies based on the plans, but --

CHAIR WEISENMILLER: Yeah, you used -- well any difference?

MR. VALDEZ: No. I completely agree. I think there's a difference between an emergency shutdown and a loss of power. I mean, emergency shutdown says you may lose a piece of critical equipment and you have an emergency shutdown. But you have other equipment available to help you in that emergency shutdown.

CHAIR WEISENMILLER: Right.

MR. VALDEZ: When you have a loss of power, you may have multiple, multiple pieces of critical equipments and you have no control. So you lose the unit versus an emergency shutdown, so we had -- a loss of electric power is by and far probably the greatest risk to a refinery.

CHAIR WEISENMILLER: Now, the other thing is both of you refer to the term "steady state." Now, a long time ago I did a sizing for a cogen project at a refinery and they gave me the hourly loads for a year as part of the sizing. And you could see lots of variability in that.

It certainly was not here. On-peak is low, and off-peak is high. And the way it was explained to me at the time was the variability came out of was -- did a ship show up, was a product coming in, and/or was there maintenance going through the maintenance operations around the refinery? So anyways they're pretty complex, highly variable loads on the power, or at least on the power side in that situation.

I'm assuming when you say steady state you're somehow trying to blend in those variations?

MS. RHINEHART: Yes. It definitely is highly variable. And we have a lot of equipment that has either a motor-driven piece of equipment -- a pump or a compressor and then we'll have duplicate equipment that's a turbine driven.

And so when we look at it, it's almost inversely proportional. If we were to reduce electricity you'll see natural gas increase, because we have to fire our boilers harder or our cogen make more steam. As Josh mentioned, it's an integral system of steam and electricity. But it's typically based on the drivers of pumps, compressors. If we're offloading a ship we'll be running pumps. If we're doing transfers between tanks and in units doing equipment run-ins of the different drivers it changes the electric versus the natural gas load.

CHAIR WEISENMILLER: Okay. And obviously, I mean there's different impacts of curtailment depending upon where you are in those cycles. But it's probably too complicated to get into that part.

Another question is that Gordon used the term, "Refer to your need to balance." And one of the interesting things on Aliso is we're looking at the nexus of different systems. And obviously on the power system we're balancing second by second. You know, on the gas system we were balancing on a monthly basis. And again, we're trying to shift that more to a daily basis.

And I realize you have a number of products, but when he says your criteria is balancing, what criteria is he talking about given that range we're dealing with here?

MS. RHINEHART: Well, we have gone to a daily balancing on natural gas and attempting to manage it in a tighter span to understand.

And the balancing that Gordon mentioned, is a lot depends on the quality of the crude. If the crude is heavier we'll use more natural gas. Depending on the steam load and the spare equipment availability it would go up and down, and so we typically will know better what we're doing right now and what our plan is. And then depending on if we have equipment issues it'll change that load.

CHAIR WEISENMILLER: And without getting in sensitive information, presumably in terms of your products too, you have a certain degree of balancing. I remember when we had the L.A. Harbor strike the concern was the pet. coke piling up and whether you suddenly said, "This is overflowing, we're shutting down."

So again, what without quite getting into any of the commercial information about how much storage you have for any products, but I mean roughly what is the sort of criteria in terms of balancing on your products, right? I mean, we saying the gas side we're now balancing, the power side we're balancing, but on the fuel side what are the sort of balancing problems there?

MS. RHINEHART: Well, one of the things that drives how we operate is the market. If gasoline is worth more than diesel or jet, we'll shift our operation to gasoline. And that can take one day to a week to manage maximizing gasoline production and additional constraints being not just the unit constraints, but also the tank logistics and product shipments. And vessel loading and unloading constraints at our dock.

And so there's always a limit to how much we shift refinery operation with the intent to capture the market. So I'm not sure if that explains it, but if we're running more gasoline we'll have higher rates in our fluidized catalytic cracking unit, versus maximizing a diesel draw off of our current tower to maximize the rate further.

CHAIR WEISENMILLER: And I guess the other criteria you have is with the Air Board's criteria on gasoline quality of that site.

MS. RHINEHART: Yes.

MR. HACKETT: And some of this may come back to storage capacity. Think about it as days of production. I mean, it's my experience that generally a refinery will have a few days of capacity. You know, if the place shuts down suddenly they might be able to supply gasoline for a couple of more days, but it's not a long period of time.

COMMISSIONER SCOTT: I have a question for you about the minimum amount of natural gas that we talked about, and the PUC mentioned it as well in kind of the order that they laid out?

And I'm wondering what does that mean in terms of the operations? Does that mean that you're operating at -- I don't know if this is the right phrasing -- but like a less intense steady state? Does it mean that you're kind of orderly shutting down different pieces, is it a combination of that, or is it something totally different? What is that, what does that minimum mean?

MS. RHINEHART: Do you want to take that?

MR. VALDEZ: So in general refineries utilize natural gas in very different ways and different amounts. And so looking at your facility and what it does and how it uses it, it's important to understand what do you need versus a, "What is optimal?"

I know we talked about, as the Chairman brought up earlier, the variability in a refinery. And there is a variability, but that's a controllable variability versus an uncontrollable variability.

And so by reducing natural gas utilization, by potentially shutting units down or doing other things, you have decreased your ability to respond to that variability -- that controllable variability. And it now becomes an uncontrollable variability, which introduces the risks, all right?

So we talk about steady state, and steady state does include controllable variability. It's that unknown that is the risk. And so when you start setting up minimums you start tightening your parameters. And your flexibility in a refinery is very different than when you have that ability to kind of change rates and do the things you need to do from a natural gas standpoint.

COMMISSIONER SCOTT: Okay. Thanks.

CHAIR WEISENMILLER: Yeah. I guess another question was -- and again just trying to understand it all I had heard that -- well obviously refineries are very energy intensive both on gas and electricity. And these are fairly old facilities, so the question becomes what are the energy efficiency options?

And both the utilities have different programs for this or I should say all three utilities: LADWP, Edison, and SoCalGas to encourage customers to do energy efficiency in their facilities.

And I had heard of -- anyway in the case of

Edison came up with some major energy efficiency programs at I think the El Segundo refinery. It went into the PUC for approval, and was turned down, I think under the theory that since there is a behind the meter cogen project there it was like who was going to benefit on that or are we just sort of shifting load between the two?

I mean, so question one is in terms of having gotten a warning that next winter looks bad, what can we do to move forward on potential energy, cost-effective energy efficiency at the refineries? And are there limitations in the PUC policies on what the utilities can and can't do there? That would need to be examined.

I mean, are either of you (indiscernible) --

MS. RHINEHART: Yeah, well I certainly can't speak to the El Segundo issue, but --

CHAIR WEISENMILLER: But I mean in terms of your refineries and energy efficiency?

MS. RHINEHART: Yeah, so I would tell you six months is not a very long timeframe.

And so typically, and I can't speak to any specifics about El Segundo, but I'll tell you that the refineries in Southern California are some of the most efficient in the country. Primarily because our electricity costs are so high here, and it's a huge component of our operating costs.

And so I was very impressed when I came to the Wilmington, California refinery about the level of heat integration and recovery of heat to minimize the electrical costs. And so I can only say I don't think there is a lot of low-hanging fruit in refineries.

The ones that I'm aware of are typically projects that require complete unit outages to tie in. And I would estimate the development of those projects is typically on a four-to-five year to get the detailed engineering and then fabrication and installation conducted.

And the limitations to the policy, I can't speak to anything I've heard where when we talk about energy efficiency in the oil refineries we look at the specific cost of the energy and the efficiency to be attained. We'll look at the reduction in NOx emissions in reference to reducing burning of fuel. But I've never heard of a driver or a negative effect due to the rebate program that you're talking about.

CHAIR WEISENMILLER: Okay. Great.

MR. VALDEZ: So I agree, I think refineries are extremely efficient in what they do. And the only short-term things that can be done are very minimal type things and it's more like I agree with Jolie, very longer-term type projects that you can implement. And then you need to go through the permitting process and all the other things that need to take place to do those.

And so I know there are consultants in the industry who actually come out to refineries and do energy analyses and look. And in my experience the things that they bring up are multimillion dollar projects that take a long time, long term to implement, because the refineries have looked at their efficiency for so long because of costs like Jolie said.

MR. HACKETT: And I would say also that AB 32 provides incentives for refiners to find efficiencies.

CHAIR WEISENMILLER: Well, exactly. I mean, although I think (indiscernible) with LEDs in the last five years, and their costs have come down 90 percent.

Now, when I often go by refineries at night I see a lot of lights and so I don't know when was the last time you really looked at that technology? Obviously, your industrial processes are much more complicated in that sense than if you were try to go to say variable speed. Again, that takes time although I think the one thing we -- you know, I mean the bad news on Aliso Canyon, this is my second time where a critical piece of infrastructure dies unexpectedly.

And in the San Onofre context we were always in the mode of everyone saying it's coming back soon, so don't do anything. And we were always planning for the worst and hoping for the best. And so we started taking actions assuming it wasn't going to come back even before the announcement. So I guess in this context again, even though there are things that might take longer than what we can do next week or what we can do by December we need to look at it.

MR. SCHREMP: Josh, I wanted to circle back to make sure I clearly understand what your comment was regarding when there's a curtailment call has occurred. As Jolie has pointed out and you point out, the more lead time the better, and then you can conduct some of those operational changes within your facility. Maybe depending on the facility maybe vaporizing some butane or propane to displace some purchased natural gas. But you could pull back to some minimum level and sort of maintain your planned rate, so to speak.

So but the point I think you were making, Josh, was that we're now in that position if something else were to occur, it's not like you wouldn't just dial back 10 percent. In that kind of situation that you're not in right now, but in that kind of situation you would actually have to maybe pull units down. And the reduction in refinery operations would be much more extensive than just 10 percent or more.

Is that correct?

MR. VALDEZ: Yes, that's correct.

MR. SCHREMP: And I think that's kind of reflected from what we were seeing in the operational flexibility of both quantitative and qualitative response we were getting in our confidential survey. And I think we didn't -- I mean, we were looking at how much more could you reduce and you're still operating. But I think it sort of skirted over the whole point of once we're there, there's a higher vulnerability to a next sort of call that might occur that the system just can't handle collectively, because of weather changes.

MR. VALDEZ: So what ends up happening is by nature these pieces of equipment are made to run at the maximum rates. I mean, that's just what a refinery does. They're going to buy pieces of equipment that are set up to run match rates. If it's 100,000 it's going to run 100,000 barrels per day.

What the issue comes down to is that these pieces of equipment, because they're sized so large have a minimum turndown, which says hey you can drop the rate, but you can't drop it past this point. Because at that point the pumps are no longer are able to circulate the proper amount of oil. You don't have enough -- there's a whole bunch of technical aspects that come into play here.

But because of that when you do take basic curtailment and you take a unit down to a minimum turndown, there is no flexibility after that, all right? If a unit's rated for 100,000 barrels per day and you have it at 60,000 there's no 40 or 30, it's 60 to 0. That's the kind of flexibility that you eliminate as you get rid of these parameters, in particular from a curtailment standpoint.

MR. SCHREMP: Okay.

COMMISSIONER SCOTT: I have a follow-up on that one, which is so if you're running between the maximum rate and they don't drop below rate, can you do that for awhile? And ideally you would not want to do that for awhile, I understand, you want the equipment to be running. But is that something that can be maintained for a week or two, is it something you can only do for a day, is it something you can do for months and months?

MR. VALDEZ: So it all depends on the configuration of the unit at that time. Certain pieces of equipment you can turn down, I mean turbine pumps are easy to adjust versus an electric pump. And so your turbine's out, and your electric's there, then you may not be able to do it very long.

Intermediate tankage is a big deal as well, so if you don't have the tankage to support that long-term reduction and rate then it is a very short period of time before you have to actually reduce crude rate. And overall crude rate reduction actually is the big deal from the impact to the overall fuel market.

MR. HACKETT: So a question I have then is from a perspective of people that have to run these things, is that an ongoing across the boards small natural gas cutback is a better alternative than rolling curtailments?

MS. RHINEHART: Yeah, I would say yes. And that's a big part of the better communication we can have, and I know there's a lot of confidential information, but if each refinery can work with the natural gas suppliers to understand this is our configuration. This is where we can reduce to without putting ourselves right on the minimum edge. Because like Joshua said, the equipment is variable about whether it will run reliably at the minimum rates for long.

And so it's better if we could work together to understand the configuration of Refinery X can cut this much natural gas, because it's at full operation, everything's good. And this other refinery actually is down, so their minimum might be slightly different. Again, depending on the steam demand and the configuration of the plant at that time, because refinery operation is truly variable depending on how you're running that day, what the crude is that you're running, what the product mix that you want, what tankage do you have available?

Because significant curtailments, it just doesn't work for refineries. I mean, a lot of what we've done to improve our environmental and reduce our environmental footprint has been to put in ultra-low NOx burners that have really tight orifices that plug routinely on operation. We clean burners. That's what we do.

When you change the fuel mix and minimize your natural gas they plug very quickly. It cause higher emissions and it can cause a trip of the unit, because of a fuel gas disruption, because the burner is just not designed to operate with heavier hydrocarbons because the lighter hydrocarbons burn cleaner.

MR. SCHREMP: So Jolie, talking about -- a better understanding of what these natural gas loads are and if a particular refinery is in a position where, "Yeah, we can do some curtailment," versus someone else who says, "I'm already sort of curtailed, because I've got this change." Planning this or even an unplanned situation, less of a position to take natural gas unless going to a point -- but Josh is pointing out now I'm taking other process units down. And my impact on output is much more severe.

So you mentioned daily, you have a daily natural gas balancing or demand and you're sort of looking at that more -- like real time isn't the proper phrase -- but much more closer time. Do you also do like a look ahead for utility use say over the next week and then further do you also look out further several months and look at operational changes that are planned in a refinery?

And understand that yes if we do this planned work that's all engineered as you said, years in advance: the planning for this, the contracting, the general and subcontractors, that you actually have a pretty good idea of what that purchased natural gas load might be several months in the future.

So it's almost like you can kind of forecast your own needs absent unplanned outages that come along or something else that happens in the ancillary service outside that you can't control, you can have a pretty good idea of where things might be at.

So is that something that maybe information like that could be conveyed to a third-party in a protected fashion, to have maybe a better forecastable demand load for a certain type of end use industry. Is that something that might be possible?

MS. RHINEHART: Yes. I mean, because I mentioned natural gas and electricity is such a high percentage of our operating costs, we have a very detailed budget around natural gas and electricity usage. We update every month what our forecast is for the remainder of the year. That's based on what our expected operational configuration is.

And then we certainly are constantly looking at how do we minimize our electrical usage, our natural gas usage? And we have many projects that we look into and evaluate how much will that impact our ability to reduce energy? And if we have a project we think is viable we put it in our plan. And then we calculate based on our energy usage budget moving forward, this is how much reduction in energy usage we think we'll have.

And that's all part of continuing to have a successful business is understanding how to minimize those costs. And because those costs are so substantial for us, it's a big focus for us.

But I would say yes, if there's an issue where we know -- where SoCalGas knows that they need to do maintenance or they have something they want to do there is a way to work with the refineries to understand the configuration. And if there's a better time than other for what the usage would be estimated to be.

MR. HACKETT: So it brings up a question sitting here and listening to you talk about gas demand, and I'm wondering does the plant or your refinery have an ongoing conversation with SoCalGas and you're giving them a gas demand forecast. And you guys are constantly communicating about your gas needs, etcetera?

MS. RHINEHART: Yes.

MR. HACKETT: That's all in there?

MS. RHINEHART: Yep.

MR. SCHREMP: But that's a bit more of a near term discussion.

MS. RHINEHART: Yeah.

MR. SCHREMP: Not some of the long-range outlook that we've raised a couple of times during these proceedings?

MS. RHINEHART: That's correct. Yeah, it's more of a near-term discussion. But it's --

CHAIR WEISENMILLER: Is it daily?

MS. RHINEHART: So there's been a lot today, because of the hot weather coming. So yeah so especially when there's been potential curtailment notices, it's been very frequent the last couple of days. I saw several communications from our refinery energy engineer with the SoCalGas Company.

CHAIR WEISENMILLER: Yeah, I would encourage that. I mean, obviously one of the things which has really evolved over the last year, and particularly now this summer, is we're really looking -- at this point the degree of coordination between the CAISO, LADWP, and SoCalGas is unprecedented. And certainly at least daily, so I encourage that level of communication on the part of major users like you with SoCalGas.

MS. RHINEHART: Definitely.

MR. SCHREMP: And his question is for Dave only, for any other lawyers that might be in the audience, market impacts?

Dave, thank you for your presentation on the Southern California system, I really appreciate that how sort of net short it is, kind of finally balanced.

And I wonder if you could -- and you were showing imports, you were showing a response of imports to the system to make up for the short-fall of the Exxon Mobile ESP incident, as well as higher than normal planned maintenance, and even unplanned maintenance that was much higher than normal in the system.

Could you talk a little bit about sort of the lag or the time it takes -- it's not instantaneous that imports come in -- it does take some time to bring material down from some of the routine places. And they may not have additional spare capacity to bring to bear to this market. And if so it's a foreign pool of gasoline.

So could you sort of explain what that time lag looks like and then how's that play into a rise in market clearing prices?

MR. HACKETT: Sure. So if we go back to the picture of the map. And if there's a problem in Los Angeles other refiners on the West Coast looked to figure out how to supply that. And they may be able to make the California material and get it down here, but there are two constraints there.

One is do they have the capacity to make the California cleaner burning fuels, additional capacity beyond what they're currently planning to make.

And two is there a shipping capacity? There's been a very tight market for U.S. flag shipping out here that was primarily driven by all of the crude oil production that was in South Texas. All that Eagle Ford production got moved to market out of the Corpus Christie area to Houston and to New Orleans and Lake Charles, etcetera and the northeast on American flag ships. And so that took all the spare capacity out.

And so I, for a long time, thought that one of the reasons there are high gasoline prices in California, is because all the ships have gone to Texas. And so it's high crude oil production of Texas that's caused high gasoline prices in California. It's a bit silly, but it makes the point. So there's only a limited amount of capacity of either from refining or from transport to get the stuff in here.

And so it takes then a long-range price signal to refineries around the world. And the physical delivery is -- if you are coming from the UK, you're talking a couple of months, from the time that you decide to make the gasoline in the UK and you get it on a ship and you sail through the Panama Canal and get it here. So that takes a long time.

And then there's a fair amount of market risk associated with that, in what if by the time the tanker shows up, the prices have gone back down? Then you've spent an awful amount of money and not been able to recover the cost, so those things tend to take a long time and they're risky, which helps illustrate why these prices have these extreme movements.

MR. SCHREMP: And in short, compare and contrast with some other areas that may be receiving a lot more supply routinely by marine vessel, say the northeast United States. That's a situation where you can maybe bring some additional supply to bear more quickly than you can for a West Coast Southern California market. So that makes it maybe a little easier to bring additional supply to bear, and maybe the market reaction in that region is different than that of Southern California?

MR. HACKETT: Well, I would say that it’s a function of how well things are going.

Over the last 15 or 20 years this market has gone from fundamentally short, fundamentally long, to being fundamentally short again. Now, if it's fundamentally short for a long period of time then the industry adjusts to that. And as in my jet fuel example, when there are ships coming from the UK or Korea on a routine basis. And so the market equilibrates at the incremental cost to deliver a product.

And then what we've seen is that as demand has changed in the economic downturn of 2008, the changes the distribution systems, increase in the use of ethanol in blending of gasoline created a lot more supply, and so the market went long. And so cargos left on a routine basis.

And I think if you're looking at Gordon's chart here, for the first half of '14 I guess that's relatively calm. And that sort of reflects this net export position that we've seen in the past.

MR. SCHREMP: Thank you.

Any other questions from the dais?

Well, I think I've covered pretty much all the topics I wanted to touch on for the panel discussion. Do any of the panel members have any closing remarks?

(No audible response.)

COMMISSIONER DOUGLAS: All right. I'll ask at this time, are there any -- no questions. It doesn't appear to be that there are any technical or clarifying questions from the audience, so we will move on.

Thank you very much.

MS. RAITT: Thank you.

So it sounds like we're done having public comments in the room. Now we'll just checking see if we have any on WebEx.

(No audible response.)

COMMISSIONER DOUGLAS: All right. It sounds like we do not have any public comments.

So we'll go the Chair for closing comments.

CHAIR WEISENMILLER: Okay. No, again I wanted to just thank everyone for being here for the discussion we had. I think that again, part of the -- this is a good opportunity to share information.

I mean I think it's pretty safe to say the reality is that the gas system this summer will be operating in ways it's never operated before. And we don't quite know that that means. And so certainly it's going to be that at this point we'll focus a lot on the interaction between the gas systems and the power systems. But certainly that interacts with the refinery systems and the fuel systems in important ways too.

And I think of the various agencies it's pretty easy for me to say where the ISO's headaches are. This is this is where the PUC's headaches are. This is probably where our headaches are. And so we need to stay on top of that and encourage communication back and forth.

And part of it is this is a time of change. And I mentioned how LEDs have come down. Certainly I think the other example, Monet (phonetic) always use is the cost of PV has come down dramatically, so there's been a lot of technology changes. And it's probably, as an industry, worth thinking about the implications of micro-grids, PV, LED, I mean all that stuff. It's probably important to think about some of the opportunities there.

Particularly going forward, but I know the reality is that we have to reduce our reliance on Aliso. Certainly having said that, even when you look at requirements we're not going have 114 wells back next winter, we'll have some small fraction of it -- some of it's never going to come back.

Some of the operational changes we're having. I mean EIA's estimate to me was that it could reduce the capabilities of a well by half. So again, it's regardless of what we do, we're going to have to really reduce our reliance there. And we're moving forward.

But certainly it's good for a vital industry like yours to be thinking about the implications there. And things, which you may have to much more quickly in terms of just to stay nimble to deal with the changing realities. And you know God bless it, if state government can do it, I would hope you guys can be fleet on your feet.

So, again, thanks.

COMMISSIONER SCOTT: No, that sounds good.

COMMISSIONER DOUGLAS: All right. Well, I'll join the Chair and Commissioner Scott as well in, thanking our panelists and thanking our participants today and everyone whose come or WebExed in.

As the Chair said this is a really important topic. We're all glad to have had this discussion today. And we look forward to getting public comments and follow-on work on this topic.

So with that, we're adjourned.

(Whereupon, at 12:30 p.m., the workshop was adjourned)

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