

DOCKETED

Docket Number:	23-OIR-03
Project Title:	General Rulemaking Proceeding for Developing Regulations, Guidelines, and Policies for Implementing SB X1-2 and SB 1322
TN #:	256165
Document Title:	Transcript of the 06172016 IEPR_Workshop
Description:	N/A
Filer:	Donnie Cox
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	5/3/2024 10:24:45 AM
Docketed Date:	5/3/2024

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
<i>2016 Integrated Energy Policy</i>) Supply Reliability Due
<i>Report Update (2016 IEPR Update)</i>) to Reduced Natural Gas
<hr/>) 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

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FRIDAY, JUNE 17, 2016

10:00 A.M.

Reported by:
Steve Hopkins

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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

Joshua Valdez, Tesoro

Dave Hackett, Stillwater Associates

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Public Comment

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1
2 P R O C E E D I N G S

3 JUNE 17, 2016

4 9:35 A.M.

5 MS. RAITT: Good morning, everyone, to today's
6 workshop on Transportation Fuel Supply and Reliability Due
7 to Reduced Natural Gas in Summer 2016.8 Today's workshop is part of the 2016 Integrated
9 Energy Policy Report Update or we call it the IEPR for
10 short.11 On to some housekeeping items, bathrooms are down
12 the hall on the right. Please be aware this workshop is
13 being broadcast through our WebEx Conferencing System and
14 it is being recorded. And today we have a live webcam that
15 we're hoping that the remote participants can see what's
16 happening at the front two tables. So the Commissioners
17 and the presenters will be on a live cam and the folks that
18 are remote participants can see a split screen of the
19 presentations and the front tables.20 We'll post an audio recording in a few days and a
21 written transcript in about a few weeks. And I'd like to
22 thank our presenters for being here today and agreeing to
23 present, and request that you do stick to your allotted
24 time. And I'll be reminding folks during the day of our
25 time constraints.26 At the end of the day there will be an
27 opportunity for public comments, which will be limited to

1 three minutes per person. And Kevin Barker -- Kevin, if
2 you could raise a hand -- is the person to talk to if you'd
3 like to make comments. Just give him your name and
4 affiliation. And then after we take comments from folks in
5 the room we'll go to WebEx and you can use the chat
6 function to let our operator know you'd like to make
7 comments.

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

11 We welcome written comments. They're due on July
12 7th and the notice for the workshop provides information
13 about how to submit written comments.

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

16 COMMISSIONER DOUGLAS: Thank you very much
17 Heather.

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

23 And so today, the focus of this workshop, which
24 we really put together in response to comments by the
25 Western States Petroleum Association, expressing concern

1 about the reliability of natural gas and electricity
2 supplies and how those could affect and what implications
3 they could have, for transportation fuel production. So in
4 response to those comments, we are having this workshop
5 focused on those specific topics.

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

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

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

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

25 And as said coincidentally, we're talking in this

1 workshop about the impacts of Aliso Canyon on sort of the
2 refinery sector. And obviously this could be a severe test
3 of the system to have to deal with very high loads, without
4 Aliso Canyon as that buffer. And so, with the Flex Alerts,
5 we really want to ask everyone to do everything they can do
6 conserve energy.

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

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

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

23 As you all know, today's workshop will explore
24 the potential impacts of possible natural gas or
25 electricity curtailment due to Aliso Canyon on refineries

1 in Southern California. And we will also explore
2 mitigation strategies that may be implemented to minimize
3 the possible impacts of those potential curtailments. And
4 so I am very much looking forward to the presentations
5 today and the information that we'll get.

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

12 MS. RAITT: Great. Thank you.

13 So our first Katie Elder from Aspen Environmental
14 Group.

15 MS. ELDER: Good morning, Commissioners.

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

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

21 MS. RAITT: Yes.

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

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

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

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

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

24 Next page, see I remembered.

25 Just a few essential background facts, Aliso

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

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

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

21 What it is particularly used for is to make up
22 for system imbalances. And that's going to sound a little
23 bit nerdy, or maybe I should admit that that's gas nerd
24 talk, but non-core customers have to order and schedule
25 their own gas. They buy it themselves. They have to call

1 up and order. Actually they don't call up; they probably
2 submit it electronically -- what we call a nomination -- to
3 say, "I'm going to use X amount of gas today." And then
4 what happens is they may or may not use that "X" amount.
5 That difference would have been made up with gas from Aliso
6 Canyon. So that's what we're missing is the ability to
7 make up for those imbalances.

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

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

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

23 If you layer on top of that planned and unplanned
24 outages that inevitably occur, such as say an engine on a
25 compressor station goes down, those sorts of planned and

1 unplanned outages on top of that differential would then
2 get us into gas curtailments.

3 Let's go to the next slide.

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

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

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

19 Of those 16 days, 14 days could be large enough,
20 in our scenarios -- we get past Scenario 1 there -- that
21 the electric system could absorb. But on those other three
22 scenarios as the gas curtailment gets larger the
23 electricity system would not be able to reallocate, re-
24 dispatch, import more electricity, depend on demand
25 response. And so we would end up with electricity system

1 curtailments for as the electric operators say from load
2 shed. Next slide.

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

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

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

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

23 We do not know when exactly that will happen.
24 And we don't know what the result of that public hearing
25 will be. In the meantime we could only withdraw from other

1 wells if DOGGR approves that, consistent with the finding
2 of that. The existing wells or available wells were
3 demonstrably insufficient to support reliability. I
4 believe that that DOGGR approval has been granted and is in
5 SoCal's hands now.

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

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

20 And this is really the bottom line or cutting to
21 the chase there. In the Action Plan we tried to preserve
22 -- do as much as we could be coming up with ideas to make
23 sure that we've preserved electricity reliability. And so
24 the Action Plan expects the electric generators would be
25 curtailed first. In the modeling that we did, the

1 magnitude and the days that we looked at to create our
2 scenarios, the magnitude of the gas curtailment was never
3 larger than the electric generation load.

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

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

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

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

1 generation load.

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

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

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

24 I know that the utilities, Southern California
25 Edison, as well as LADWP, have looked at the exemption

1 lists and tried to make sure that they have the right
2 facilities on the list.

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

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

6 Thank you, Catherine, for your presentation.

7 And next we have Gordon Schremp from the Energy
8 Commission.

9 (Pause to set up for the next speaker.)

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

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

19 We do have a great deal of information, so my
20 comments are going to be sort of split into two parts. The
21 first is going to be a little bit of an overview of the
22 refineries, sort of a refinery 101 review, just for
23 context-setting purposes. And then I'll be talking about
24 the results of our analysis of refinery fuel use that does
25 include purchased natural gas germane to the concerns just

1 discussed by Katie as well as other types of fuel they use
2 still gas, and in some case liquid fuels that are gasified.

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

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

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

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

23 Also, I want to note that there is no pipeline
24 connection between Northern California refineries and
25 Southern California. These movements must be by marine

1 vessel almost predominantly. And that's that little bar.

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

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

12 Go ahead, Gordon.

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

22 So here are the locations of the six primary
23 refineries in Southern California producing California
24 specific fuel. There are some other smaller facilities
25 that do produce asphalt, lube oils, and some other

1 solvents. So here are the primary facilities and their
2 crude oil capacity.

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

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

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

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

21 This is just meant to convey that refineries have
22 a lot of process units that are designed to change the
23 composition structure, combine smaller chain hydrocarbons
24 together to make longer chains, break up hydrocarbons. And
25 so they use a variety of techniques to do that, a lot of

1 heat a lot of pressure, a lot of catalysts, and a lot of
2 hydrogen. Next slide please.

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

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

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

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

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

25 So this is just meant to show that there are

1 differences in the quality of these fuels used by
2 refineries. Purchased natural gas is on the right hand
3 column. And the refinery gas or still gas that is produced
4 in the refinery by processing crude oil and operation of
5 other process units is of a different quality. Clearly
6 highlight it's not mostly methane; it's only a portion of
7 that. A lot of hydrogen is in there, a lot of other
8 constituents.

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

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

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

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

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

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

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

25 So most important -- how much natural gas are the

1 refineries using? So as a percent of total SoCalGas system
2 send-out it does -- in this time period did max out at a
3 little over 13 percent and the lowest point was actually
4 9.4 percent. So you can see variability from one month to
5 the next, as a large end-use customer, that in some cases
6 is always refinery operational-based.

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

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

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

24 So we look ahead to see -- and the orange dots on
25 this slide are actually not planned maintenance -- and the

1 takeaway is that if you look at the shaded areas that's how
2 high they were in 2015. So FCCU stands for Fluidized
3 Catalytic Cracking Unit, the primary gasoline producing
4 process equipment at the refinery. You see that that was
5 almost unprecedented in the history of over the last ten
6 years of the amount of gasoline production capability
7 offline. And so that means their demand for natural gas
8 was lower than it would have been. Next slide, please.

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

11 MR. SCHREMP: Okay.

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

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

25 This is the relative concentration or ratio of

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

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

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

1 see how much it is with the total system.

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

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

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

16 CHAIR WEISENMILLER: Thanks Gordon, a couple of
17 questions.

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

22 MR. SCHREMP: No. No, I don't. But maybe that's
23 something Katie could help with right here and now? But
24 it's something I think we have the ability to reach out to
25 the industry post workshop, in some form of follow-up

1 analysis, to try to get a better quantification around that
2 question.

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

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

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

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

1 We've had colder years than that. If you look at
2 1948 throughout the entire West it was like three standard
3 deviations. So bottom line is that coverage, I think it
4 probably behooves everyone to start thinking about ways to
5 reduce gas use next winter.

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

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

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

25 So we're just suggesting that refiners do know,

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

8 CHAIR WEISENMILLER: Yeah, that's good.

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

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

21 MR. SCHREMP: That certainly merits a further
22 discussion. It's our understanding on working with the
23 refineries over the years, especially AB 32 related, the
24 Air Resources Board and the South Coast Air Quality
25 Management District emission rules, that the refineries

1 have actually undertaken a number of efficiency projects
2 within the refineries. These are usually low-hanging fruit
3 that have an immediate economic return. And so these kinds
4 of more modest capital projects do get funded. So they
5 have become much, much more energy efficient over time.

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

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

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

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

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

23 And you mentioned earlier that there was still 15
24 billion cubic feet of gas at Aliso Canyon. I was just
25 curious what that number represented as a percentage of the

1 capacity prior to the leak?

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

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

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

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

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

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

22 The wells that would be plugged or isolated would
23 be wells that it's going to take longer to get them through
24 the testing process. And over time SoCal, as I understand
25 the inspection plan, Safety Inspection Plan, will continue

1 to review additional wells each month. There's only so
2 many that they can test at a time. They can only get I
3 think it is eight rigs onsite at Aliso Canyon at a time, so
4 it's just going to take several months to get through.

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

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

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

23 MS. ELDER: That was my understanding too, that
24 there's about 20 wells that were actually out of service at
25 the time that the leak occurred. And that SoCal was going

1 to permanently plug those. And what I've heard the gas
2 engineers say is that that probably involves concrete in
3 the well bore. But again, I'm not that kind of expert.

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

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

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

12 MS. ELDER: Hi, Jairam.

13 The forecast of natural gas consumption for the
14 refineries is about 500 MMcf per day. So contrast that
15 with average demand say of 2.8, 2,800 MMcf per day, on an
16 average day. And maybe you're at -- I think SoCalGas is
17 forecasted one 35 peak day is something like 5.1 Bcf or
18 5,100 MMcf. So on a peak day it's roughly maybe 10
19 percent of SoCal's overall throughput.

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

1 customers.

2 MS. RAITT: More questions, anyone?

3 (No audible response.)

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

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

8 MS. RAITT: Great, thank you.

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

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

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

20 One thing that I think merits noting is that
21 Katie mentioned the Action Plan. And one of the mitigation
22 measures in the Action Plan was to put in what we call
23 tighter balancing rules. And in effect, create incentives
24 for customers to bring in supply close to what is forecast
25 to be burned. So that has been done in a little different

1 method than balancing. It's been done through tightening
2 up what's called an operational flow order, which
3 essentially creates incentives. And sends messages to the
4 market that you need to bring in more gas to meet expected
5 demand.

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

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

22 They were localized and typically well-
23 coordinated with the customers. Customers knew well in
24 advance that there was going to be a curtailment, so that
25 number can be misleading. But what we're really looking at

1 is the number 15, the one that fell outside of that. And
2 that was a curtailment that happened as a result of a
3 number of conditions overlaying on June 30th and July 1st
4 of last year.

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

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

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

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

1 So next slide, please?

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

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

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

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

23 And in response to the application the generators
24 came back and said, "The percent that you're going to first
25 curtail electric generators is not appropriate for the two

1 different seasons: the winter season and the summer
2 season." So they asked for an adjustment for that.

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

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

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

17 MS. RAITT: I'm sorry.

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

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

1 EG. Next slide, please?

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

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

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

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

1 and if we hit the next slide?

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

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

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

17 CHAIR WEISENMILLER: Yeah, a couple of questions.

18 First was -- obviously one of the items of the
19 Action Plan was to look at the -- well okay so SoCalGas
20 typically does maintenance in the summer, because peaks are
21 in the winter. And there's also the overlay of the various
22 safety tests that need to be done. So one of the early
23 Action Plan items was to determine what their maintenance
24 plans were for the summer. And then to try to make that
25 difficult decision, particularly for the safety questions,

1 you know thinking of what we could do in terms of possible
2 deferral of actions.

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

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

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

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

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

21 MR. REISINGER: Yeah.

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

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

6 CHAIR WEISENMILLER: Okay.

7 MR. REISINGER: Historically.

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

15 Is that still embedded in the framework?

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

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

23 It also -- and I didn't mention -- does separate
24 this into 10 zones, so that it does away with this issue
25 where you're curtailing somebody over here and it can't

1 impact where the problem is over here.

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

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

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

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

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

18 MR. REISINGER: Yes.

19 CHAIR WEISENMILLER: Great. Thank you.

20 MR. REISINGER: You're welcome.

21 Are there questions?

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

24 MR. REISINGER: Uh-huh?

25 COMMISSIONER SCOTT: So you mentioned that it's

1 awaiting a proposed decision and that it would be
2 implemented in about 90 days after approval.

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

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

11 (phonetic)

12 COMMISSIONER SCOTT: I see. Okay. Thanks.

13 MR. REISINGER: Yep.

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

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

18 MS. RAITT: Not that I know of.

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

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

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

24 MS. RAITT: So, thank you.

25 So next is Dave Hackett from Stillwater

1 Associates.

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

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

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

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

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

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

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

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

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

20 So, remote and isolated -- I mean it doesn't feel
21 like we're remote and isolated -- but as far as the world
22 is concerned I think we are. And so when production is
23 curtailed, the additional supply has got to come from
24 someplace. And we've seen the impact of that, I think,
25 over the years of primarily when unexpected refinery

1 maintenance happens, if there's a power failure or some
2 other kind of problem. I think the latest one was at
3 Torrance Exxon, the Exxon Mobil refinery at Torrance that
4 had a problem in February of '15 that still is not quite
5 rectified. And we'll see the impact of the pricing here in
6 a moment on that, next slide.

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

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

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

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

7 That's the objective of this exercise.

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

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

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

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

1 the Bay Area is long. Next slide.

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

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

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

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

17 Gordon did a really good job I think with this ad
18 hoc survey that they put together in less than a week. We
19 actually have some numbers to look at about how much
20 natural gas is consumed by the refineries and where in the
21 refinery that it's consumed and so this pretty much just
22 supports what Gordon had to say. But there's the basic
23 refining processes, which you're boiling oil and cracking
24 it. The cleanup of the oil that takes the contaminants
25 out, that's the hydrogen manufacturing. The refineries

1 can't make California's ultra-clean fuel without hydrogen.

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

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

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

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

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

23 One thing that's clear is that all of the process
24 units, the burners and heaters that have been put in
25 recently, meet the highest standards of emissions

1 reduction. And so they're all running on natural gas.
2 They may not have the plumbing it takes to be able to
3 switch to propane, but I think that we'll need to ask the
4 refiners for their view on that.

5 Okay, next slide and the next one.

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

11 These places run 24-7, 365 if they can do that.
12 They really don't want to shut them down unless they have
13 to. And we've seen demonstrated the problems when the
14 electric supply is disrupted. The one that comes most to
15 mind is the one at Exxon Mobile Torrance, in October of
16 2012, which caused a big price spike. And that actually I
17 think was the genesis of the Petroleum Market Advisory
18 Committee. That was the event that brought us together
19 there.

20 And then also as well, the logistics system
21 requires electricity to deliver the fuel that pump the
22 gasoline away from the refinery either to the propriety
23 distribution terminal that Chevron, or Exxon, or Shell
24 might have. Those same pumps pump to the KinderMorgan
25 System. It's the KinderMorgan System that distributes the

1 product to the rest of the state. That's true in Northern
2 California as well as in Southern California.

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

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

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

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

25 And so it may be worth having a conversation with

1 the interested parties about what flexibility refiners
2 have, in order to do some sort of substituting, given from
3 now until the winter time to figure it out.

4 CHAIR WEISENMILLER: Yeah.

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

7 CHAIR WEISENMILLER: Great.

8 MS. RAITT: Questions?

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

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

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

23 MR. HACKETT: Let's see. The longer term is
24 easier to address, because the refineries like any other
25 large plant, have a maintenance cycle. And so every three-

1 to-five years everything in the place gets taken down and
2 fixed up and brought back up again.

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

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

10 COMMISSIONER DOUGLAS: All right, thanks.

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

16 MR. HACKETT: So the --

17 CHAIR WEISENMILLER: Or other airports,
18 obviously?

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

23 And so those import flows are actually fairly
24 well-established, because they're happening on a regular
25 basis. There is a regular movement of jet fuel tankers

1 from Asia, from Korea, or Japan or Singapore, coming into
2 California. It's a normal practice.

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

7 COMMISSIONER DOUGLAS: All right, thank you.

8 Any clarifying or technical questions from the
9 audience?

10 (No audible response.)

11 MS. RAITT: No.

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

14 MR. HACKETT: You're welcome.

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

18 MR. HANSEN: Thank you.

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

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

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

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

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

23 In addition, the confidential survey contained
24 questions regarding potential operational flexibility. And
25 as also you heard from Mr. Schremp, the WSPA member

1 companies have cooperated fully in providing the CEC with
2 the requested confidential business proprietary
3 information, all for the purpose of assisting this
4 Commission, assess the potential impacts on transportation,
5 fuel production and availability that could result from any
6 natural gas curtailment events during the summer.

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

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

14 COMMISSIONER DOUGLAS: All right, thank you.

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

16 Thanks.

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

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

24 CHAIR WEISENMILLER: Thank you.

25 MS. RAITT: Great, thank you.

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

6 (Pause to set up Panel.)

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

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

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

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

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

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

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

23 The safety of the personnel and the surrounding
24 community is of paramount concern to me in my current role.
25 I'm appreciative of being involved in this important

1 discussion regarding Aliso Canyon as steady supplies of
2 natural gas and electricity are necessary and integral to
3 the safe and reliable operation of oil refineries. As
4 such, we are critically concerned about the reliability of
5 energy supplies that are threatened by the current
6 circumstances surrounding the Aliso Canyon.

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

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

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

24 In addition, emergency responses put significant
25 risk on our people, the community, the refinery equipment,

1 and can take a week or longer to return to normal
2 operations and resume production of transportation fuels.

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

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

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

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

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

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

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

25 Just as the Public Utilities Commission, an

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

8 Thank you.

9 MR. SCHREMP: Thank you, Jolie.

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

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

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

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

22 Refineries are complex just like Jolie said.
23 They run at extremely high pressures, extremely high
24 temperatures, they use highly reactive catalysts. These
25 are things that are very dangerous in nature, and so these

1 units and these refineries are built to operate at a steady
2 state. And so any time you introduce change into them you
3 introduce risk and not only risk to the people on the
4 ground, the operations individuals, but you introduce to
5 the equipment, to the market supply of hydrocarbon or fuel
6 to Southern California, as well as to the community. And
7 so doing what we can to keep that steady state is extremely
8 important.

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

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

21 At the same time from a natural gas standpoint
22 natural gas comes into a very big role, plays a very big
23 role in refineries, in particular around safety systems,
24 pilot gas and heaters, flare gas, burner tips, your tank
25 blanket gas -- all of these things that are extremely

1 important, both to the refinery itself and local
2 communities, who rely on natural gas heavily.

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

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

20 MR. SCHREMP: Thank you, Josh.

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

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

10 So thank you for that Josh.

11 And thank you Jolie for your introductory
12 remarks.

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

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

1 those could be touched on if the curtailment is so great in
2 the system.

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

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

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

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

23 And so when you have an emergency shutdown,
24 you're essentially just shutting the whole piece down on
25 its own. And so when I talk about emergency shutdowns and

1 loss of power specifically, it's just like pulling the plug
2 out versus maybe rebooting your computer, except our
3 planned shutdown takes multiple, multiple days.

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

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

19 But if you plan it you slowly reduce the rate,
20 you stage the equipment, you can follow your procedure.
21 The emergency shutdown is pull the plug and figure out
22 where you have issues. You can damage equipment. You can
23 have bowing of your catalyst trays and distribution
24 headers. And essentially the emergency shutdowns are just
25 to get it into a safe state and then you have to figure out

1 how to dig out of that hole that you've created.

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

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

9 COMMISSIONER DOUGLAS: Okay. Thanks.

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

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

22 MS. RHINEHART: Well, I would rephrase it a
23 little bit only to say the sooner that we know the better.
24 Because there is, depending on the configuration of the
25 plant and what plant equipment we have, we can certainly

1 communicate what the potential is for us to -- as Dave
2 talked about earlier -- to put butane or propane into fuel
3 to offset the natural gas that we can.

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

8 Does that answer the question?

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

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

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

25 So there were some differences for that type of

1 operation?

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

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

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

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

25 MR. VALDEZ: It is, but at the same time a cogen

1 facility doesn't necessarily have the ability to respond,
2 because it's dependent on the refinery. And so some of the
3 things that Jolie has stated around equipment being out of
4 service, things of that nature, crude availability, the
5 dissolution profile of that crude, may or may not provide
6 enough gas to be fueled in order to support the cogen.

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

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

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

20 MR. VALDEZ: Thank you.

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

23 MR. REISINGER: I just had a comment --

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

1 (Pause to situate microphone.)

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

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

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

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

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

23 MR. SCHREMP: Thank you.

24 And Josh, you have a comment on that?

25 MR. VALDEZ: Yeah, so the current curtailment

1 policy that's out there, or the one that is waiting to be
2 implemented, allows the consumers of natural gas to have
3 flexibility as far as where they curtail.

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

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

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

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

24 MR. VALDEZ: So it's only facilities that are
25 directly under your span of control, so you wouldn't be

1 able to play it if it was an Air Products facility or a
2 Praxair facility. It's only within your span of control.

3 MR. SCHREMP: Okay. Thank you.

4 I did want to pursue --

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

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

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

12 CHAIR WEISENMILLER: I realize that, yeah.

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

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

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

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

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

7 CHAIR WEISENMILLER: Right.

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

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

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

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

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

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

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

22 Another question is that Gordon used the term,
23 "Refer to your need to balance." And one of the
24 interesting things on Aliso is we're looking at the nexus
25 of different systems. And obviously on the power system

1 we're balancing second by second. You know, on the gas
2 system we were balancing on a monthly basis. And again,
3 we're trying to shift that more to a daily basis.

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

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

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

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

23 So again, what without quite getting into any of
24 the commercial information about how much storage you have
25 for any products, but I mean roughly what is the sort of

1 criteria in terms of balancing on your products, right? I
2 mean, we saying the gas side we're now balancing, the power
3 side we're balancing, but on the fuel side what are the
4 sort of balancing problems there?

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

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

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

23 MS. RHINEHART: Yes.

24 MR. HACKETT: And some of this may come back to
25 storage capacity. Think about it as days of production. I

1 mean, it's my experience that generally a refinery will
2 have a few days of capacity. You know, if the place shuts
3 down suddenly they might be able to supply gasoline for a
4 couple of more days, but it's not a long period of time.

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

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

16 MS. RHINEHART: Do you want to take that?

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

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

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

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

14 COMMISSIONER SCOTT: Okay. Thanks.

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

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

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

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

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

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

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

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

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

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

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

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

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

19 CHAIR WEISENMILLER: Okay. Great.

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

1 that need to take place to do those.

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

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

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

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

23 And in the San Onofre context we were always in
24 the mode of everyone saying it's coming back soon, so don't
25 do anything. And we were always planning for the worst and

1 hoping for the best. And so we started taking actions
2 assuming it wasn't going to come back even before the
3 announcement. So I guess in this context again, even
4 though there are things that might take longer than what we
5 can do next week or what we can do by December we need to
6 look at it.

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

17 So but the point I think you were making, Josh,
18 was that we're now in that position if something else were
19 to occur, it's not like you wouldn't just dial back 10
20 percent. In that kind of situation that you're not in
21 right now, but in that kind of situation you would actually
22 have to maybe pull units down. And the reduction in
23 refinery operations would be much more extensive than just
24 10 percent or more.

25 Is that correct?

1 MR. VALDEZ: Yes, that's correct.

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

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

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

25 But because of that when you do take basic

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

7 MR. SCHREMP: Okay.

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

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

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

1 crude rate reduction actually is the big deal from the
2 impact to the overall fuel market.

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

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

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

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

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

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

22 So you mentioned daily, you have a daily natural
23 gas balancing or demand and you're sort of looking at that
24 more -- like real time isn't the proper phrase -- but much
25 more closer time. Do you also do like a look ahead for

1 utility use say over the next week and then further do you
2 also look out further several months and look at
3 operational changes that are planned in a refinery?

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

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

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

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

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

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

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

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

25 MS. RHINEHART: Yes.

1 MR. HACKETT: That's all in there?

2 MS. RHINEHART: Yep.

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

5 MS. RHINEHART: Yeah.

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

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

11 CHAIR WEISENMILLER: Is it daily?

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

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

1 MS. RHINEHART: Definitely.

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

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

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

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

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

23 MR. HACKETT: Sure. So if we go back to the
24 picture of the map. And if there's a problem in Los
25 Angeles other refiners on the West Coast looked to figure

1 out how to supply that. And they may be able to make the
2 California material and get it down here, but there are two
3 constraints there.

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

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

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

23 And so it takes then a long-range price signal to
24 refineries around the world. And the physical delivery is
25 -- if you are coming from the UK, you're talking a couple

1 of months, from the time that you decide to make the
2 gasoline in the UK and you get it on a ship and you sail
3 through the Panama Canal and get it here. So that takes a
4 long time.

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

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

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

23 Over the last 15 or 20 years this market has gone
24 from fundamentally short, fundamentally long, to being
25 fundamentally short again. Now, if it's fundamentally

1 short for a long period of time then the industry adjusts
2 to that. And as in my jet fuel example, when there are
3 ships coming from the UK or Korea on a routine basis.
4 And so the market equilibrates at the incremental cost to
5 deliver a product.

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

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

15 MR. SCHREMP: Thank you.

16 Any other questions from the dais?

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

20 (No audible response.)

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

25 Thank you very much.

1 MS. RAITT: Thank you.

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

5 (No audible response.)

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

8 So we'll go the Chair for closing comments.

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

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

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

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

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

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

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

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