

STATE OF CALIFORNIA - THE RESOURCES AGENCY  
BEFORE THE  
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of, )  
 )Docket No. 11-IEP-1L  
 )  
Preparation of the 2011 )  
Integrated Energy Policy Report )  
(2011 IEPR) )

**Transportation Committee Workshop:  
Transportation Fuel Infrastructure Issues**

CALIFORNIA ENERGY COMMISSION  
HEARING ROOM A  
1516 NINTH STREET  
SACRAMENTO, CALIFORNIA

MONDAY, MAY 11, 2011  
9:30 A.M.

Reported by:  
Peter Petty

COMMISSIONERS

James D. Boyd, Vice Chair and Presiding Member,  
 Transportation Committee  
 Tim Olson, His Advisor  
 Carla Peterman, Commissioner and Associate Member,  
 IEPR Committee  
 Saul Gomez, Her Advisor

STAFF

Suzanne Korosec, IEPR Lead  
 Malachi Weng-Gutierrez  
 Gordon Schremp, Senior Fuels Analyst, Fuels and  
 Transportation Division

Also Present (\* Via WebEx)

Presenters

John Brautigan, Valero  
 Tim Carmichael, NGVC  
 Tom Turrentine, UCD  
 Ed Heydorn, Air Products  
 \*Steve Eckhardt, Linde  
 Matt Horton, Propel Biofuels  
 Jim Uihlein, Chevron  
 Eric Bowen, Renewable Energy Group, Inc.,  
 CA Biodiesel Alliance  
 Matt Tobin, Kinder Morgan PL  
 Jim Iacoponi, Propel Biofuels  
 Chuck White, Waste Management  
 Michael Waugh, CARB

Panelists

Richard Lowenthal, Coulomb  
 Paul Heitmann, Ecotality  
 Joel Pointon, San Diego Gas & Electric (SDG&E)  
 Russell Vare, Nissan  
 Dan Bowermaster, Pacific Gas & Electric (PG&E)

Public Comment

Dwight MacCurdy, SMUD  
 Gina Grey, WSPA  
 Dwight Stevenson, Tesoro

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## P R O C E E D I N G S

1  
2 MAY 11, 2011

9:34 A.M.

3 VICE CHAIR BOYD: Welcome to this Transportation  
4 Committee Workshop. The Notice of April 27<sup>th</sup> was pretty  
5 specific as to the mission and purpose of this workshop;  
6 Preparation of the 2011 Integrated Energy Policy Report  
7 is our target. I am Jim Boyd, the Presiding Member of  
8 the Transportation Committee and, as you may have  
9 noticed at the time the Workshop Notice went out, I was  
10 the lone Commissioner on the Transportation Committee,  
11 however, subsequent to that Workshop Notice, our newest  
12 Commissioner sitting to my left, Carla Peterman, became  
13 the Associate Member of the Transportation Committee, so  
14 I am no longer as lonely as I was there for a period of  
15 time. And in a few minutes, I will, after giving some  
16 background on this, I will ask Carla if she'd like to  
17 say some - offer the opportunity, anyway, to make some  
18 comments about being a member of this committee and the  
19 workshop for today. It is a Transportation Committee  
20 Workshop on Transportation Fuel Infrastructure Issues.

21 The workshop today is being webcast and you'll  
22 probably hear more about that in just a minute from Ms.  
23 Korosec when I turn the opportunity over to her. The  
24 purpose, as enunciated in the Hearing Notice is to  
25 discuss Transportation Fuel Infrastructure and the

1 issues confronting California related thereto,  
2 particularly with reference to the production, the  
3 delivery, the distribution, and the storage of  
4 transportation fuels, as well as the adequacy of supply  
5 of petroleum, renewable, and alternative fuels. And, of  
6 course, you can't talk about these issues without  
7 reference to the demand therefore.

8           A set of key questions were laid out in the  
9 hearing notice and I will not repeat that. The  
10 background for IEPR production and hearings therefore,  
11 I'm sure, will be discussed by Ms. Korosec, so I won't  
12 go into that. I will just point out there was an  
13 attachment to the hearing notice, referencing issues to  
14 be discussed that laid out a large number of issues that  
15 we and the staff would like to hear from the public and  
16 stakeholders on, with reference to this overall topic.  
17 And in addition to the testimony we expect to hear today  
18 and the presentations by staff, there of course is an  
19 opportunity for stakeholders and the public to make  
20 written comments and you will be reminded of the  
21 procedures and the timetable for that, it's referenced  
22 in the Hearing Notice.

23           And with that, I would like to offer the  
24 opportunity to my new associate committee member to make  
25 a few comments before we go back and return to the

1 agenda and turn the issue over to Ms. Korosec, who also,  
2 I'm sure, has to tell us about emergency procedures and  
3 how to evacuate the building and the other things  
4 required of such hearings. Ms. Peterman.

5 COMMISSIONER PETERMAN: Good morning. Thank  
6 you, Commissioner Boyd. Hello, everyone. Glad to have  
7 been selected to participate on the Transportation  
8 Committee. Considering the share of greenhouse gases  
9 that a transportation sector can contribute and its role  
10 in our economy, I think it's a very important committee  
11 to be on, particularly our work exploring other  
12 opportunities for alternative fuels. The infrastructure  
13 issues are key and are an area where the State can  
14 contribute great insight, and so looking forward to the  
15 comments in this discussion today and working with all  
16 of you going forward. Thank you.

17 VICE CHAIR BOYD: Thank you. Would you like to  
18 introduce your Advisor?

19 COMMISSIONER PETERMAN: Yes, I would.

20 VICE CHAIR BOYD: Because I just met him. He's  
21 that new.

22 COMMISSIONER PETERMAN: Thank you. I have a new  
23 Advisor, Saul Gomez, and he comes to us with a  
24 background in renewables, electricity infrastructure and  
25 transportation. He has experience with the Legislature

1 and CERT, and I think he will be a valuable asset to my  
2 team, to the Commission, and to this Committee.

3 VICE CHAIR BOYD: Thank you. And I would note  
4 that my Advisors are conspicuously absent and I hope to  
5 be joined by at least one of them as the day progresses,  
6 but they're both taking care of fire drills that are  
7 consistent around here, and I hope to be joined by at  
8 least Tim Olson in the not too distant future, but he's  
9 taking care of some issues for me, plus they know I've  
10 been around here so long that I probably wouldn't give  
11 them a chance to speak anyway, or maybe they think I  
12 don't need the help that I know that I need on this  
13 subject. In any event, Ms. Korosec, having totally  
14 blown your calendar and done the introduction on your  
15 agenda and done our opening comments, I'll turn it back  
16 to you. I thought it would be better to introduce the  
17 subject from up here before you get to the fire drills  
18 and etc. etc. So Suzanne, if you would please.

19 MS. KOROSEC: All right. Good morning, I'm  
20 Suzanne Korosec. I manage the Energy Commission's  
21 Integrated Energy Policy Report Unit. The Energy  
22 Commission produces an IEPR every two years that  
23 includes assessments and forecasts of energy supply,  
24 demand, production, transport, delivery, and  
25 distribution for the State's energy sectors, including

1 the transportation fuel sector, and these assessments  
2 and forecasts are used to develop energy policies that  
3 are intended to ensure that California has enough energy  
4 to meet its needs and that energy is reliable,  
5 affordable, and environmentally benign. This year, the  
6 IEPR schedule is consistent with past IEPRs, we plan to  
7 have a draft report out in late September with a hearing  
8 on the draft in mid-October, and hope to adopt near the  
9 end of November.

10 As Commissioner Boyd noted, I need to cover some  
11 housekeeping items before we get started. For those of  
12 you who may not have been here before, restrooms are in  
13 the atrium, out the double doors and to your left. The  
14 glass doors near the restrooms, please be aware those  
15 are alarmed, they are for staff use only, if you try to  
16 go out, you will trigger an alarm. We have a snack shop  
17 on the second floor at the top of the atrium stairs  
18 under the white awning where you can get coffee, and if  
19 there's an emergency and we need to evacuate the  
20 building, please follow the staff out the door to the  
21 park that is diagonal to the building, and wait there  
22 until we're told that it's safe to return.

23 Today's workshop is being broadcast through our  
24 WebEx conferencing system and you need to be aware that  
25 you are being recorded. We will make an audio recording

1 available on our website in a couple of days, and we'll  
2 have a written transcript available within about two  
3 weeks.

4           We have a public comment period today at the end  
5 of the agenda and, during that period, we'd like you to  
6 please fill out blue cards, or comment cards, those are  
7 available on the table out in the foyer, with your name  
8 and affiliation, and please give those to Jessie who is  
9 here near the WebEx console. We'll take comments first  
10 from those of you here in the room, followed by comments  
11 from those who are participating via WebEx. For those  
12 of you in the room, when it's time for you to speak,  
13 please come up to the microphone at the center podium so  
14 we can make sure your comments are heard by those on  
15 WebEx and also appear in the transcript. It's also  
16 helpful if you can give our transcriber your business  
17 card so we make sure that your name and affiliation are  
18 correct. WebEx participants can either use the chat or  
19 raised hand feature to let the Coordinator know that you  
20 have a question or comment, we'll either convey your  
21 question or open your line so you can ask it yourself at  
22 the appropriate time. Anyone who is participating by  
23 phone only and is not logged into WebEx, we'll open your  
24 phone lines at the very end of the public comment period  
25 to give you an opportunity to speak.

1           We're accepting written comments on today's  
2 topics until close of business May 23<sup>rd</sup>, and the notice  
3 for today's workshop, which is available on the table in  
4 the foyer and also on our website outlines the process  
5 for submitting comments to the IEPR Docket. And with  
6 that, I'll turn it over to Malachi.

7           MR. WENG-GUTIERREZ: Good morning,  
8 Commissioners.

9           VICE CHAIR BOYD: Good morning, Malachi.  
10 Somebody should respond.

11           MR. WENG-GUTIERREZ: All right, so, again, today  
12 we are talking about transportation fuel infrastructure  
13 issues. I'm just going to be giving a quick overview,  
14 letting the speakers who we have lined up today speak to  
15 most of the issues. Hopefully, we'll have many of the  
16 questions that we had posted in our notice in the  
17 attachments addressed in the conversations that ensue  
18 today.

19           So, in the morning we'll be talking basically  
20 about the Infrastructure and Demand Integration  
21 methodology that we'll be using for this IEPR cycle.  
22 We'll follow that with a discussion about Retail  
23 Refueling and Recharging Infrastructure and the issues  
24 that could arise in those areas, and then, after lunch,  
25 we will have a few speakers that will also be in the

1 Retail Fueling and Recharging Infrastructure topic on  
2 that topic. And then, at the end of the day, we'll have  
3 a couple of other items, the Renewable Fuels: Supply  
4 Import & Distribution topic, and then the Crude Oil  
5 Import Forecast and the High Carbon Intensity Crude Oil  
6 (HCICO) screening topic, which all will be very  
7 interesting, I'm sure. So, at the very end of the day,  
8 as Suzanne mentioned, we will have a public comment  
9 period and hopefully, as we have it outlined, we should  
10 be done about 5:00 today. So it is a full day and we'll  
11 try to move it along and ensure that we have adequate  
12 time for both public comment and questions and  
13 discussions.

14 I had this slide in here just in case it wasn't  
15 covered, but I think Commissioner Boyd you already  
16 covered it, and Suzanne also mentioned it. I just  
17 wanted to highlight the reliability component, the  
18 security element, and then the element of diversifying  
19 the energy supplies as being kind of important elements  
20 of this requirement.

21 VICE CHAIR BOYD: Well, thank you for doing that  
22 because I neglected to push the subject hard enough. I  
23 didn't want to flash that slide in front of people two  
24 or three times during the day.

25 MR. WENG-GUTIERREZ: There is a lot to that

1 slide, so... So, in the Fuels and Transportation  
2 Division, we do a number of things and I'm just  
3 highlighting a few of the elements of the activities  
4 that we perform there. As we presented in our February  
5 24<sup>th</sup> workshop, we actually develop fuel price scenarios  
6 and evaluations for our Demand Forecasts, we develop our  
7 Demand Forecasts throughout the year, and then we intend  
8 to present them on August 16<sup>th</sup> in a workshop on our  
9 outputs. In addition to the General Over-Archiving  
10 Transportation and Fuels, I also wanted to pull out the  
11 transportation - the electricity transportation Demand  
12 Forecasts that we produce in the Fuels and  
13 Transportation Division. That is a forecast that we  
14 produce and we provide to the Demand Analysis Office,  
15 that they then include into their analyses of demand, so  
16 they add that to their overall residential and  
17 commercial industrial demand for electricity, and they  
18 get from us the transportation component; so, they look  
19 to us as the source for that demand.

20 In addition to those items, we also quantify  
21 regional supply and demand trends historically and also  
22 going forward, to identify potential issues that could  
23 arise in regional demand. So, as I'm sure Gordon will  
24 mention, as we've mentioned in the past, we look at a  
25 number of states, not just California, but also Arizona

1 and some other neighboring states, to see how their  
2 demand requirements might influence our infrastructure  
3 requirements in the state to supply them with their  
4 transportation fuels, as well.

5 Of course, we evaluate infrastructure adequacy  
6 issues and we consider our projected demand scenarios in  
7 those evaluations, and we look at the sources and  
8 production capacity of different types of transportation  
9 fuels in our analyses.

10 So, in our February 24<sup>th</sup> Workshop, we talked  
11 about a couple of overarching themes that we would be  
12 kind of talking about throughout our analyses, this is  
13 one of them, we've gotten some feedback from the  
14 Commissioners and others and I think we're going to  
15 highlight energy security as one of the elements that we  
16 will be looking to and discussing in our report. So,  
17 the two elements that we're focusing on when we talk  
18 about energy security are diversification and then the  
19 sourcing of different fuels, transportation fuels. And  
20 as I say here, obviously the idea - the benefit of  
21 diversification would be to limit the exposure of the  
22 transportation market to single fuels, or to a very  
23 small number of fuels. Of course, there is the  
24 potential if you move from one field to another, if the  
25 new field that you're having introduced has a high price

1 volatility or other complications, you need to consider  
2 that in your evaluation and in your recommendations for  
3 activities associated with increasing energy security.

4           The fuel sources should be both reliable,  
5 stable, and should meet the California specifications  
6 and this, as we diversify our fuels, there are added  
7 infrastructure requirements. All of that adds to the  
8 complexity of distributing transportation fuels in  
9 California and all those things need to be kind of  
10 considered and included in our analysis.

11           This is a slide that I showed at our February  
12 24<sup>th</sup> workshop. I've added the actual goals, the AB 1007  
13 goals that were identified for alternative fuel use and,  
14 again, this is a California-wide transportation fuel  
15 demand. And the two lines in there are from our 2009  
16 IEPR, so the red one is our low petroleum demand, which  
17 would correspond with a high alternative fuel use, and  
18 then the blue line obviously is our high petroleum  
19 demand, so that would equate to a lower alternative fuel  
20 use. So, you can see in the early years, the green  
21 triangles there are the goals - nine percent in 2011,  
22 eleven percent in 2017. We intend to meet those goals  
23 pretty easily. The goal that we are not meeting under  
24 our IEPR 2009 analysis was the 2022 goal and you can see  
25 that that's fairly - we're pretty shy of meeting that

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1 goal.

2           Of course, the new IEPR analysis may hold  
3 different results and we will have that for you in  
4 August. One of the things that I wanted to - it's not  
5 illustrated here, but I did want to point out, was that  
6 the primary component of this alternative fuel use and  
7 the large gain in alternative fuel use from 2012 to 2022  
8 is due to ethanol use in California, primarily due to  
9 the RFS2 adjustment we did to our demand analysis. So,  
10 the major component of the alternative fuels that are  
11 being observed here are primarily natural gas and  
12 ethanol.

13           Overall, this is another slide that I've  
14 presented before, but it basically shows our inputs at  
15 the top. In the middle where it's kind of bolded  
16 squares or rectangles there, those are kind of the  
17 sectors or the areas of demand that we primarily look  
18 at. Results in our California field demand, which is  
19 the green box in the lower left, and that both is  
20 relevant to and also gets information from the supply -  
21 California fuel supply component. Obviously, today  
22 we're talking about the transportation energy  
23 infrastructure, which is influenced both by supply  
24 capacity, as well as what we intend to be future demand.  
25 So there's an interaction there between the supply and

1 demand and the infrastructure requirement that I wanted  
2 to just illustrate there.

3           Our demand scenario methodology, we're going to  
4 have a two-step approach, we're going to be running the  
5 initial models to get our base demand numbers and those  
6 will be dependent upon all of our inputs and the policy  
7 scenario developments that we've defined, and we  
8 mentioned in our February 24<sup>th</sup> workshop. That initial  
9 modeling activity would then be followed by a post-  
10 processing activity, which we would adjust the demand  
11 for different fuel selection processes, as well as  
12 sectors, not necessarily included in our demand models,  
13 and then also adjusting for different policies.

14           And so, specifically, the post-processing  
15 activities for the fuel selection in sectors, because of  
16 the bi-fuel component, or the multiple fuel use for  
17 PHEVs and E85 FFVs, that's something we have to kind of  
18 evaluate outside of the current model. We do have  
19 specifications for those decisions being made on the  
20 basis of infrastructure availability and pricing, so  
21 those are done outside of the existing model structure.  
22 In addition, we typically evaluate off-road fuel  
23 consumption and add that to our General Demand Forecast,  
24 and then also, as post-process activity, we have  
25 analyzed certain other policies of program compliance.

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1 We have to basically evaluate our outputs and make sure  
2 we see how close we are to program compliance given  
3 their current estimates for vehicle population, to  
4 comply with that standard, given their schedule. And  
5 then we also look at the RFS2, or the Renewable Fuels  
6 Standard, and the Low Carbon Fuel Standard policies, and  
7 those will both be post-processing activities that we  
8 will be handling in this IEPR cycle.

9 I'm going to turn the mic over to Gordon and  
10 have him speak in a little bit more detail about those  
11 post-processing activities and how that will be handled  
12 for the Renewable Fuel Standard and LCFS.

13 MR. SCHREMP: Thank you, Jesse, thank you,  
14 Malachi. Good morning, Commissioners, new Advisor. My  
15 name is Gordon Schremp, I'm a Senior Fuels Analyst in  
16 the Fuels and Transportation Division at the California  
17 Energy Commission. As Malachi mentioned, I will be  
18 going through some slides talking about some of the  
19 post-processing work.

20 It's important to note, as Commissioner Boyd  
21 stated at the outset, that part of this process is to  
22 get feedback from stakeholders, people who are experts  
23 in the industry, people who work in these subject areas  
24 as business or NGOs, provide us, please, with your  
25 experience and input as we move forward in the process.

1 We can only be as good and accurate as the information  
2 we receive and sort of the education we receive as part  
3 of our ongoing process. So, to that end, we try to be  
4 as transparent as feasible and provide stakeholders with  
5 clarity on what our assumptions are going to be. People  
6 can disagree with them, but we want to be clear on what  
7 we're assuming because it's very important to the Demand  
8 Forecast, the infrastructure assessments, and what we  
9 assume is going to be sort of part of our baseline. So,  
10 the purpose of this slide is to show you some of the key  
11 assumptions we're making, moving forward, and please  
12 provide comment to us. Suzanne covered the close date  
13 of May 23rd; feel free to weigh in on some of these  
14 subjects.

15 But it's very important that the Renewable Fuel  
16 Standard, the Federal Regulation, is a fair share  
17 compliance, it's a company-wide compliance in the United  
18 States. For purposes of analysis, we're assuming fair  
19 share is meant by actually blending and using those  
20 volumes in California and not necessarily over-complying  
21 in other regions of the U.S. and applying those credits  
22 to your nationwide obligations.

23 Further, people will talk about this a little  
24 bit later, but the new changes by the U.S. EPA to allow  
25 E15 and about two-thirds of the existing light-duty and

1 SUV fleet is something we don't think will happen in  
2 California any time soon, in fact, over the forecast  
3 period. So, is it feasible to occur? Yes. Many steps,  
4 many years to go through to even get to that point, but  
5 there are lots of issues associated with E15 that others  
6 will speak to. So, for our purposes, we're assuming E10  
7 is the maximum low level blend wall.

8           There are many different carbon intensities,  
9 those can be changing with new information provided to  
10 the Air Resources Board, and we are going with the  
11 current versions as posted by the Air Board online. We  
12 understand the indirect land use change - and there is  
13 both direct and indirect as part of the overall total  
14 carbon intensity of specific fuels - we're assuming that  
15 the indirect land use change will remain as is for  
16 purposes of our calculation, but we recognize that this  
17 issue is going to continue to be discussed by the Air  
18 Board and the Advisory Panel members, and ultimately  
19 reach a resolution that is indeterminate at this time,  
20 meaning a 50 percent reduction in the indirect land use  
21 change can possibly be offset by other modifications to  
22 information that go into calculating direct and indirect  
23 carbon intensities of fuels. So, those are assumptions,  
24 please feel free to compel us to change our mind.

25           As I mentioned, the RFS2 Federal requirement, it

1 is a company-wide volume, renewable volume obligation.  
2 And so it's not a per gallon regulation. So, primarily  
3 more ethanol, more than we can use in low level gas  
4 blends, it's going to lead to E85.

5           There were concerns about feedstock being used  
6 to convert to fuel and putting pressure on feedstock  
7 prices, and so that's something why I think U.S. EPA  
8 capped it at 14 billion gallons. But certainly, it's  
9 going to displace gasoline as it did in our 2009  
10 Forecast, it will do it again this go-round, as well,  
11 and we're looking at a need for increased  
12 infrastructure, of course, what we're here today.

13           This slide is only intended to illustrate that  
14 the Regulation has some concerns at this point, the main  
15 is cellulosic biofuels, maybe over-reaching at this  
16 point, it's either been significantly downgraded in the  
17 obligation by U.S. EPA, 250 million gallons became, I  
18 think, approximately six million gallons for 2011, it's  
19 half a billion next year, we certainly don't see that  
20 kind of capacity available at this point in time, and I  
21 don't think EIA or U.S. EPA does either, so that will be  
22 downgraded. So this has concerns about trying to  
23 project volumes and, in particular, specific types of  
24 renewable fuels that are important, that have  
25 infrastructure and fuel availability differences.

1           Post-processing does change the forecast results  
2 that Malachi discussed as part of our modeling work, and  
3 that will do primarily - push down the gasoline  
4 component, the petroleum hydrocarbon component of the  
5 gassing demand. So it's going to decline lower than it  
6 is today. And we'll elevate E85 beyond what the  
7 modeling results with, say, consumers and vehicle and  
8 fuel availability would dictate normally. So it's going  
9 to be sort of a forcing function and that has other  
10 issues for business purposes, as well as getting  
11 consumers to consume that much E85 in California.

12           We are close to the blend wall in the United  
13 States. E15 has not been officially approved, there are  
14 labeling requirements, there are warranty issues, so  
15 this is not a given to start any time soon, even in the  
16 United States, but there are certainly many proponents  
17 out there that want to move forward on E10, but we're  
18 assuming in California that E10 blend wall is going to  
19 be a hard cap in low level blends throughout the  
20 forecast period.

21           VICE CHAIR BOYD: Gordon, question?

22           MR. SCHREMP: Yes.

23           VICE CHAIR BOYD: Does it take E15 for the  
24 nation to meet the RFS goals that have been established?

25           MR. SCHREMP: The use of E15, or the initial

1 request to use a higher blend E15, was done because  
2 there was concern heating the blend wall, we would not  
3 be able to blend all the ethanol that you're referring  
4 to under RFS2 obligations; however, E15 does not get one  
5 to the end of the RFS2 obligations, all it does is delay  
6 the inevitable, meaning hitting the low level blend  
7 wall, whether it's E10, E12, E15, by a couple of years.  
8 So, it won't necessarily solve and obviate the need to  
9 sell lots of E85, it will just delay that.

10 VICE CHAIR BOYD: So it's a trade-off  
11 potentially between increasing the ethanol component of  
12 gasoline or selling a lot more E85?

13 MR. SCHREMP: Right, which has retail  
14 infrastructure cost and who will invest implications,  
15 which has adequacy if Flex Fuel Vehicle is a big issue;  
16 so, yes, it's very important, but it won't be a silver  
17 bullet if, in fact -

18 VICE CHAIR BOYD: I may be getting ahead of you,  
19 but the other component in my mind is the fact that the  
20 Renewable Fuels Standard goals are predicated on so much  
21 from corn, so much from cellulosic sources, and the  
22 Federal Government has repeatedly relaxed or delayed the  
23 cellulosic component for lack of much cellulosic  
24 ethanol. I presume that, too, enters into the  
25 discussions of the need for E15 or how much E85 you need

1 to meet the Renewable Fuels Standard if the standard  
2 keeps getting delayed, so to speak.

3 MR. SCHREMP: That's a very good point. It's  
4 unknown exactly how U.S. EPA will continue to handle the  
5 inadequate availability of cellulosic ethanol in  
6 commercial volumes. Will they modify the total volume  
7 of renewable fuels under the mandate, modify only this  
8 portion of the advance and shift it into more advanced,  
9 which would be Brazilian ethanol, or shift it into  
10 biomass-based diesel, which has lot of other issues we  
11 haven't talked about? So, just saying, no, it's not  
12 that much and we don't change anything else is possible,  
13 but it's possible they'll just shift that into some of  
14 the other categories. So, once again, that's sort of a  
15 challenge not only for us trying to do some forward  
16 thinking demand analysis, but certainly a challenge for  
17 those who are striving to comply each and every year  
18 with its obligation throughout the nation and in  
19 California. So, it's created a great deal of  
20 uncertainty. It would be valuable if U.S. EPA weighed  
21 in on this, and ultimately Congress has to modify these  
22 requirements, so we would hope that there would be a  
23 continued dialogue, an expanded dialogue on how to  
24 modify so that we have an achievable set of Federal  
25 goals here.

1 VICE CHAIR BOYD: Thank you.

2 MR. SCHREMP: So why would we care about looking  
3 at how much more E85? Well, we think there is a  
4 significant amount of retail infrastructure that would  
5 be required. You see all kinds of lines on this chart,  
6 this is from 2009, and you see a line like 30,000  
7 additional dispensers, well, that's quite a bit, and  
8 5,000 down here. So, the low case has us looking at  
9 California needing quite a few more dispensers to market  
10 E85, depending on the average throughput per dispenser,  
11 change the volume, change the throughput calculation,  
12 and then you get a very large variation in the demand.  
13 However you look at this, though, it's a very daunting  
14 increase in the number of dispensers. Propel, who is  
15 going to speak today, has been installing dispensers at  
16 existing retail establishment, as has Pearson Biofuels,  
17 so companies are out there endeavoring to improve the  
18 availability of E85 at retail, but there's an awful lot  
19 of demand for these kinds of dispensers and capability  
20 to be seen and this will be a large focus of our  
21 infrastructure renewable fuel assessment at retail.

22 COMMISSIONER PETERMAN: Gordon?

23 MR. SCHREMP: Yes.

24 COMMISSIONER PETERMAN: Why do we see a decline  
25 in dispensers in later years under some of the case

1 scenarios?

2           MR. SCHREMP: Good question. This is  
3 essentially an artifact of going up to 2022 where the  
4 RFS2 obligation stops. Clearly, we believe they won't  
5 just plateau, but they'll likely keep increasing, and so  
6 we've held that steady and, when you do that, the actual  
7 demand will decline because there's total fuels going  
8 up, so the E85 portion goes down. So it's really more  
9 of an artifact, so if we were to, for example, make an  
10 assumption that the renewable fuel components go up one  
11 percent per year, then these lines wouldn't just peak  
12 and decline, they would continue rising, but possibly a  
13 different slope.

14           The other post-processing assessment is the Low  
15 Carbon Fuel Standard, the California Regulation. It is  
16 a per gallon carbon intensity, not total volume, so it  
17 doesn't matter how much gas and diesel fuel is sold in  
18 California, ultimately, every gallon, you know, each  
19 quarter, has to fully comply when companies, obligated  
20 parties, sort of true up their debts and credits under  
21 the carbon umbrella. So this regulation began in 2011,  
22 January, there are still a number of important issues  
23 yet to be resolved in this regulation. Credit trading,  
24 like in the renewable identification number system in  
25 the Federal program, transparent credits, a market one

1 can go into and purchase as part of your obligation  
2 strategy, does not yet exist in California, although the  
3 regulation is underway. There is a proposed screening  
4 for crude oils to - the Air Resources Board would not  
5 want to have certain high carbon intensity crude oils  
6 used in California. If they are, the incremental carbon  
7 should be offset, and we will talk about that a little  
8 bit later, after lunch.

9           The indirect land use, I already mentioned,  
10 that's a big issue, but enough information and no  
11 resolution on this issue to date and we don't expect  
12 resolution in time for us to finalize our forecast, so  
13 we will go with the existing indirect land use change  
14 carbon intensities today.

15           So we've done some preliminary analysis and the  
16 concern under RFS2 is more E85, diesel is very low, we  
17 haven't looked at - we haven't completed looking at the  
18 Low Carbon Fuel Standard; unlike the Federal  
19 requirement, there is a very small amount of biodiesel  
20 under the Federal Standard. California, on the other  
21 hand, there could be a strong demand for bio and  
22 renewable diesel to lower the carbon intensity of diesel  
23 gallons. So that's the significant difference. The  
24 LCFS will change the different flavors one would want to  
25 use in California, but not necessarily increase the

1 total volume of renewables on the gasoline side of the  
2 ledger, but for diesel, much more so. So, the Federal  
3 requirement isn't a big deal on the diesel side of the  
4 equation, but even though it's a small amount, there are  
5 problems, and some will speak to this in terms of lack  
6 of biodiesel availability in the United States and very  
7 high prices.

8           So we're very concerned looking mid to longer  
9 term in the forecast, insufficient supply of low carbon  
10 fuels that are going to be needed. So that's a big deal  
11 and infrastructure, of course, to import and distribute  
12 those. And then we expect, certainly, that fuel prices  
13 will increase. These fuels are more expensive and we  
14 expect them to become even more expensive as demand for  
15 certain types of low carbon intensity fuels start to  
16 really kick in, not necessarily this year, but the next  
17 two, three, to four years. And if you look at some of  
18 the RIN credit prices in those markets, they've gone up  
19 rather dramatically and some of those volume  
20 requirements are very modest, so that's certainly a  
21 concern, but we have no credit trading information to  
22 look at, at this point in time.

23           So, what does it look like? Well, in total, it  
24 changes the mix. The blue is Brazilian at the bottom.  
25 These two colors, the top two, are Midwest, that gets

1 phased out, its carbon intensity is too high as you move  
2 forward in the regulation, and we're using a small  
3 amount of all the California ethanol, but very  
4 significant volumes of biodiesel, which gets to price  
5 availability. No ethanol from Brazil was imported into  
6 the United States in all of 2010. And, in fact, Brazil  
7 was importing some ethanol, so will the supplies be  
8 there? And if they are, at what price increase? So  
9 these are definitely concerns. This shows that, if  
10 you're selling E85, compliance with the Low Carbon Fuel  
11 Standard is easier. You can continue using Midwest  
12 ethanol primarily and a little bit of Brazilian and  
13 achieve full compliance. But that's only the minority  
14 portion of the total gasoline and gasoline-like fuels  
15 being sold.

16 So, our concern is there's no feasible solutions  
17 out there at this point in time. Is there time for  
18 cellulosic ethanol to become available in commercial  
19 quantities, you know, five or six years from now? Yes,  
20 there is, however, lack of progress over the last 20,  
21 and especially last 10 and five years, it does raise  
22 concern about will that be there. So, time will tell  
23 and we certainly hope more information is put into our  
24 process, as well as U.S. EPA's assessment of the RFS2.  
25 So, I think that's it for now. I would be happy to take

1 any questions from the dais at this time.

2 COMMISSIONER PETERMAN: Gordon, I heard that  
3 there were projects looking at sugar-based ethanol in  
4 the southern states in the U.S. I was wondering what  
5 the status of any U.S. projects along this line.

6 MR. SCHREMP: I am not aware of any  
7 announcements that financing and permitting has been  
8 completed, and that a construction schedule has been put  
9 into press. We understand that sugarcane-based ethanol  
10 in, say, as you mentioned, Southern states, Florida, but  
11 especially in the Imperial Valley in California is  
12 probably the optimal growing location for sugarcane,  
13 even better than Florida. It has some of the cheapest  
14 water cost anywhere in the United States. That has been  
15 an area of intense investigation by farm cooperatives  
16 and Ag associations down there, large farmers, about  
17 looking at growing cane and even sugar beets, going down  
18 there for the sugar markets, using integration with  
19 existing sugar plants and displacing things like the  
20 alfalfa that use as much water as cane. So, an awful  
21 lot of work has been done on that, but yet no announced  
22 construction projects starting soon, so certainly I  
23 assume that, not knowing anything else, that the costs  
24 are still quite high, otherwise you would see this  
25 because there is an RFS2 obligation for advanced that,

1 with sugar-based ethanol would completely qualify, so  
2 they certainly have - there is a demand target out there  
3 that is not available in the United States, so if you  
4 could build it, your competition is going to be Brazil.  
5 So we haven't seen that yet, but it doesn't mean it  
6 can't happen. Any other questions?

7 VICE CHAIR BOYD: I'll make a comment and that  
8 is, I mean, we're setting up a situation in my mind  
9 where California could drive the price of Brazilian  
10 ethanol sky high and I think, as a State, and as a  
11 nation, we need to think about that.

12 MR. SCHREMP: Well, I think the President of  
13 Brazil is already thinking about things like that with  
14 recent announcements to the effect of maybe shifting who  
15 has responsibility for setting the ethanol concentration  
16 in gasoline, as well as changing how ethanol - or,  
17 excuse me - cane mills operate, meaning what ratio of  
18 sugar to alcohol production they can get to some maximum  
19 or some minimum levels. So there is a recognition about  
20 just availability of adequate ethanol supplies to meet  
21 Brazil's demand, which their gasoline demand is growing  
22 three, four, or five percent per year, unlike that of  
23 the United States. So they recognize the concern about  
24 adequacy supply, let alone your second point, what will  
25 be market clearing prices if there is a large demand

1 pull and the market clearing prices have to be high  
2 enough to attract it, and especially to overcome the  
3 \$.54 import tariff; that's why it's much more expensive.

4 VICE CHAIR BOYD: Thank you, Gordon.

5 MR. SCHREMP: Thank you.

6 VICE CHAIR BOYD: As you are leaving, let me  
7 just comment to the audience and stakeholders, when we  
8 get to the testimony, I would be interested in hearing  
9 from stakeholders about the subject that came up here in  
10 this discussion about the possible failure of the nation  
11 to reach the RFS goals because of delays in realizing  
12 the cellulosic component goals, and what people think  
13 about that, and does that address the need of the nation  
14 to look at other alternative fuels to realize our  
15 overall alternative fuel introduction goals, rather than  
16 just our ethanol component thereof. In any event,  
17 something I think we would be interested in hearing  
18 about if folks have any comments when they make their  
19 testimony.

20 MR. SCHREMP: Well, thank you, Commissioners,  
21 and I'll introduce our first presenter of the day, John  
22 Brautigam from Valero. John, the mic is yours.

23 MR. BRAUTIGAN: Good morning. Thank you for  
24 letting me speak to you. I'm the Vice President of  
25 Strategic and Regulatory Development for Valero. I deal

1 with fuels regulations, from working with the EPA or the  
2 State Regulators, giving them advice as to how to write  
3 the regulations so we can comply, and going back,  
4 working usually as a capital plan for like lowering  
5 sulfur in gasoline or diesel, or with the RFS2 and the  
6 Low Carbon Fuel Standard, a supply plan for supplying  
7 lower carbon fuels, working with the marketing people,  
8 we develop a strategy, put it together, and then follow  
9 through and make sure that we're in compliance with the  
10 regulations.

11 VICE CHAIR BOYD: Well, welcome, John. I'm  
12 thrilled to see that California issued you a Visa to  
13 enter the state!

14 MR. BRAUTIGAN: In the presentation, is it page  
15 down? Hang on while my eyes - okay - in the  
16 presentation, I'm going to talk about RFS2 and LCFS  
17 issues. We see some major compliance concerns getting  
18 to the same things that Gordon talked about, just the  
19 blend walls and lack of infrastructure, cost of  
20 infrastructure, for E85 and just adequacy of  
21 infrastructure for importing 100 percent of California's  
22 ethanol from Brazil. I'll talk about RFS2 first, then  
23 LCFS, have a summary, and then the HCICO, I'll come back  
24 later on this afternoon.

25 I put this in a question and answer format just

1 to try to get right at the issue, I actually got some of  
2 the questions from the Energy Commission and we made up  
3 some of our own. One of them was, "What if the blend  
4 wall remains at E10 in California?" And this is related  
5 to the RFS2. Well, yeah, it would hurt RFS2 compliance  
6 because at some point you need to blend more than 10  
7 percent ethanol and whatever gasoline and at a company  
8 like Valero, we're making gasoline in California plus  
9 outside of California. If California stays at 10,  
10 outside of California would have to be even higher. The  
11 real question is, I don't think people are aware of the  
12 whole nature of the blend wall issue. You cannot sell  
13 E15 today legally, except for Flex Fuel Vehicle. The  
14 blend wall is a multi-layer wall, or a barrier. The  
15 Sub-Sim regulations is what the EPA issued a waiver for,  
16 the waiver is contingent on proper dispenser labeling  
17 and a retail survey requirement, which will be  
18 established in a final rule that hasn't been issued yet,  
19 it's still at the Office of Management and Budget, and  
20 approval of health effects test under Section 211(b) of  
21 the Clean Air Act, so once those three things get done,  
22 then as far as in the EPA's eyes, it's okay. But then  
23 we have additional problems. The RFG regulations will  
24 be fixed with the final rule for the labeling, but the  
25 CARB regulations for CARB Phase 3A, they don't allow you

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1 to go over 10 percent; the Arizona regulations don't  
2 allow you to go over 10 percent. There are many State  
3 laws, there are State regulations out there that don't  
4 allow you to blend over 10 percent, or that reference  
5 ASTM Standards and NIST Standards as being the gasoline  
6 in Texas must meet ASTM Standards. Well, the ASTM  
7 Standards don't go over 10 percent. And if anybody  
8 wants to see a paint drying very slowly, go watch ASTM  
9 move on an issue, okay?

10 Then, you've got the kevlar layers, the warranty  
11 issues, and the lack of them for original equipment and  
12 extended warranties, and the liability issues. I mean,  
13 as Valero, we are not going to sell a product that  
14 violates the warranty of the automobile of our customer.  
15 So, that issue has to be resolved before we sell E15.

16 E85, it has its own problems. Installing the  
17 dispensers is nearly impossible to justify unless you  
18 have a high subsidy. The 5,000 dispensers at about  
19 \$100,000 each, you're talking \$500 million in your base  
20 case for California. You can say, "Okay, the majors - I  
21 go to a Valero station," well, not all the Valero  
22 Stations are owned by Valero, and that's the say way,  
23 about 80 percent of the gas stations out there in the  
24 U.S. are owned by small - it's individuals that own one  
25 or two stations. There are some chunks like Kwik Fill

1 and other distributors that have multiple stations, but  
2 a lot of these stations are owned - somebody owns one or  
3 two stations, and they make about \$40,000 a year. So  
4 how do they get the money to spend \$120,000? Because if  
5 it's a retrofit, it's going to be about \$120,000 to dig  
6 up the station and put in an E85 dispenser. And then  
7 you're going to have a problem potentially on pricing,  
8 okay?

9           If the ethanol is cheap enough, it makes money,  
10 too blended in a gas, or you could make money blending  
11 it into gasoline. Consumers, because of the lower  
12 mileage, want E85 - tend not to fill up Flex Fuel  
13 Vehicles unless the E85 is priced below their gasoline  
14 which generally is E10. If the ethanol is being priced  
15 close to gasoline, because that's its value in E10, it  
16 may be priced at a point that you can't discount the E85  
17 enough to sell the volume through the E85 pump that  
18 you're trying to sell, there's just - there's a problem  
19 there as to what is setting the ethanol price out in the  
20 market. Okay?

21           Next issue, cellulosic ethanol. We are aware of  
22 one - and I know their names, but I don't want to say  
23 who it is - one 25 million gallon per year cellulosic  
24 ethanol plant that is moving forward, it is probably one  
25 to two years away. The problem is, it costs \$200

1 million. I mean, where are we going to get the capital  
2 to build all these cellulosic ethanol plants? To date,  
3 no cellulosic RINs have been operated under the EPA RFS2  
4 system, which - any cellulosic ethanol that was made for  
5 fuel purposes could generate RINs beginning July 1<sup>st</sup> of  
6 this year; no cellulosic RINs have been made. The  
7 demonstration plants that are out there are not selling  
8 their cellulosic ethanol for the fuel market. Okay? In  
9 the future, we expect the EPA is going to have to lower  
10 not only the cellulosic ethanol amount, but also when  
11 they have the authority to do this, the advanced  
12 biofuel, and the total renewable fuel obligation,  
13 because there isn't going to be enough either sugarcane  
14 ethanol to come in and make up to meet the advance  
15 requirement, or biodiesel out there.

16           Okay, RIN prices. What are they telling us?  
17 Biodiesel RINs are \$1.28 a gallon. Each gallon of  
18 biodiesel generally generates 1.7 RINs, that is saying  
19 that there is not enough biodiesel out there to meet the  
20 2011 standard. The EPA's website is showing how many  
21 RFS2 biodiesel RINs are being made in January and  
22 February, was running at a rate of about .3 or .4  
23 billion gallons per year, and the requirement is .6 this  
24 year. Okay? So there is a possibility there is going  
25 to be an industry, in total, that is going to have to

1 run a deficit for the biodiesel RIN obligation for the  
2 RFS2 program this year, and it's because half of the  
3 biodiesel plants were shut down, they were small  
4 operations and they don't have the capital to  
5 recapitalize because the biodiesel credit was taken  
6 away; on the remaining plants, a lot of them were shut  
7 down and need money for capital to recapitalize. So we  
8 just see a problem there. And the advance RINs are  
9 based on some ethanol coming in from Brazil under the  
10 Caribbean Basin Initiative and not paying the tariff,  
11 and the two-cent price for the corn RINs is just saying  
12 that the corn ethanol-based production is greater than  
13 the standard, or the requirement this year. The  
14 cellulosic RINs, like I said, there aren't any, there  
15 are quotes out there, these are quotes, I believe, from  
16 various trade sources, and they're not a quote of a  
17 given day, they are approximately numbers, okay? The  
18 cellulosic RINs are running \$1.15 a gallon. You can go  
19 and buy a cellulosic allowance this year from the EPA  
20 when you go to fill out your compliance and it will cost  
21 you \$1.13, but that cellulosic allowance can't be used  
22 against the advance or total renewable standard where  
23 the cellulosic RIN can, but that's telling us that the  
24 cellulosic allowance, or the cellulosic ethanol is just  
25 not out there.

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1           Unlike - I remember being in the refinery when  
2 we had lead phase down, expanded a reformer, doubled the  
3 catalyst size, I was working on a refinery still and  
4 went from Process Engineering to P&E when PPM diesel  
5 came in, then I remember actually working with fuels  
6 regulations for RFG, the MSAT, the MSAT2 Regs, the RFS,  
7 RFS2, CARB3-3A, ULSD. All of those Regs, we could see a  
8 clear path of, "Yes, we'll do this," "We'll put in this  
9 desulfurization unit at this refinery, we'll treat these  
10 streams, or this stream, and we'll meet the Reg." For  
11 the RFS2, we don't see a way to meet the RFS  
12 requirements. We don't see how you get around the cost  
13 of the E85, and we don't see getting around the problems  
14 of the E10 blend wall. We think Congress is going to  
15 have to go back and potentially reduce the volumes  
16 required that they put in the law and that the EPA may  
17 have to issue waivers as soon as 2011 or 2012.

18           VICE CHAIR BOYD: At this point, could I ask you  
19 a question about your company's views -- and I believe  
20 this question is for anybody later on -- your views on  
21 the long term viability, I guess I want to say, of  
22 biodiesel vs. perhaps the use of renewable diesel in the  
23 future.

24           MR. BRAUTIGAN: I think - I'm going to have  
25 trouble answering that. I don't know all the production

1 economics; the problem is we don't - there's a plant in  
2 Finland, another plant in Indonesia that Neste has, and  
3 I don't know their production economics. Valero has  
4 announced that we're working on a plant to start up  
5 hopefully in the end of 2012, there will be renewable  
6 diesel, but we don't have a FAME or a Fatty Acid Methyl  
7 Ester, the traditional biodiesel plant, so I really  
8 don't know the biodiesel economics. I think the  
9 renewable diesel will be close to biodiesel in price, or  
10 to be able to match it, the problem is of not having  
11 enough feedstock. We're going to run out of waste,  
12 grease and fat, and you can make renewable diesel from  
13 soybean oil or palm oil, it's just a different  
14 processing step and you don't have to use waste, grease,  
15 and fat. So, I think both will still be there, and I  
16 think, you know, the EPA is going to set the mandate in  
17 the outer years, so we'll see what they do. Does that  
18 answer your question?

19 VICE CHAIR BOYD: Yeah, I think you got as close  
20 as probably most people can to the question. I guess I  
21 just have a long term concern about the worldwide demand  
22 for diesel fuel. Once economies, or most nations get  
23 back on track, I think we'll continue the developing  
24 nations' greater and greater utilization of  
25 transportation fuel, in general, but particularly diesel

1 as they move their goods and services to the world  
2 market more and more, as they improve their economies  
3 and this, to me, is going to continue the incredible  
4 pressure on diesel supply - diesel of any and all kinds  
5 - and with diesel fuel again priced far in excess of the  
6 cost of gasoline, at least in this state of late, which  
7 is a repeat of past history. And the difficulties with  
8 biodiesel, which parallels some of the difficulties in  
9 the sense of hurdles that have been laid out with regard  
10 to ethanol, that I wonder about the long term viability  
11 of biodiesel vs. pushing harder for renewable diesel,  
12 and just pushing harder for more and more diesel to meet  
13 the demand; or, again, as I said in the earlier  
14 question, shifting to other alternative fuels in greater  
15 proportion to meet the needs of that sector of the  
16 transportation economy that heretofore has relied upon  
17 diesel fuel. Because I doubt other countries will go as  
18 fast as the alternatives in that arena has as we might  
19 have the capability or the need, so just general  
20 questions. Thanks for taking a stab at that.

21 MR. BRAUTIGAN: Yeah, I agree with you on the  
22 demand outlook, but renewable diesel has an advantage,  
23 you could put it at the head of the pipeline vs. the  
24 biodiesel, but I think - how big a significant portion  
25 of the worldwide diesel demand, I think we're just going

1 to run out of feedstock for renewable diesel or  
2 biodiesel, even if we use the soybean or palm oil for  
3 renewable. LCFS, we have concerns with the LCFS also  
4 because, remember, if you met the Federal RFS, too, you  
5 wouldn't necessarily meet California's Low Carbon Fuel  
6 Standard. The LCFS is piling on, on top of that. One  
7 of the questions the CEC was asking about Brazilian  
8 ethanol, we see problems with that just as having the  
9 infrastructure to bring it all in; the problem becomes a  
10 capital one, that there's been a project, the sponsor  
11 was looking to put in a port here in Sacramento to bring  
12 in ethanol imports from Brazil, you have Gordon last  
13 year showing, "Hey, here's what you could do with  
14 ethanol from Brazil coming in," yet the market today is  
15 backwards, Brazil's is higher than the U.S., and if  
16 cellulosic - or, it really isn't "if," it's "when,"  
17 that's the problem because we don't know when - when  
18 cellulosic ethanol is available, you're going to tend to  
19 use that instead of the Brazilian ethanol. So how do  
20 you get funding to beef up the infrastructure to bring  
21 in Brazil ethanol when that project may not have a 20-  
22 year lifetime, okay? We just see a lot of - we also  
23 just see it as shifting ethanol around the checkerboard,  
24 just like we're shifting crudes and we'll talk about  
25 that in the afternoon.

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1           The cost - I know one of Gordon's slides had  
2 \$1.80, \$1.50 or \$1.80 if the market is moving around, is  
3 about how much more a gallon of ethanol would cost if  
4 you landed it in today from Brazil. So if you had a 10  
5 percent ethanol blend, it would cost the consumer  
6 approximately \$.15 more for his final gasoline that he's  
7 putting into his car. Low CI Biofuels, "What would  
8 happen for the competition for those if the LCFS  
9 expanded in the northeast states? We're looking at a  
10 potential LCFS." We just see it, you know, the price  
11 would go up. We just see an increase in cost to  
12 consumers, more and more ethanol shuffling all around  
13 the country, and which we think is just going to raise  
14 CO<sub>2</sub> emissions. We don't see a big benefit of just moving  
15 ethanol from a Midwest plant because part of this is  
16 associated with wet DGS to California and bringing in a  
17 little from this planet, a little from that planet. You  
18 know, the ethanol would have been there anyway. Same  
19 thing, LCFS, we don't see a way to comply in the outer  
20 years. We're worried about meeting the percentages and  
21 that gets into - I can build a spreadsheet and I can put  
22 down a whole bunch of, "Oh, yeah, we're gonna have a  
23 whole bunch of cellulosic ethanol." But that doesn't  
24 mean it's going to come about and we're looking at not -  
25 by 2015, we think there's a good possibility that we're

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1 going to have, as an industry and as a company, have  
2 problems meeting the percent reduction standards.  
3 Remember, if you had - and some of this gets back into  
4 the assumptions, like if you're assuming not much E85,  
5 and you had E10, if you had a cellulosic ethanol at 100  
6 percent reduction in CI, okay, say it had no CI, but it  
7 would have to be negative because the baseline is 98,  
8 but say it was zero, so you have like a 98 percent  
9 reduction in CI, that's 10 percent of your blend, so  
10 that's like 10 times 98 is 9.8, but it's only seven  
11 percent of your blend on an energy content basis, so  
12 now, you know, I'm not even going to get to the 10  
13 percent of my blend with 100 percent cellulosic ethanol  
14 in the CARBOB, and I still have got to do something for  
15 the diesel pool. So we just see problems.

16 In summary, I'm not going to read through all  
17 this, like I said, it's all the regulations before we  
18 could see a clear strategy how to get there, both the  
19 RFS2 and the LCFS, we think there is some problems and a  
20 good possibility of some major road bumps where Congress  
21 and EPA for the RFS2 and CARB for the LCFS may have to  
22 revisit the programs, just because afraid of surprise  
23 implications or supply implications.

24 Thank you. Do you have any other questions at  
25 this time?

1           VICE CHAIR BOYD: Thank you. I have no further  
2 questions.

3           COMMISSIONER PETERMAN: I have no questions.

4           VICE CHAIR BOYD: Thank you very much.

5           MR. SCHREMP: John, this is Gordon and I just  
6 have one quick question. You mentioned that companies  
7 can now purchase from U.S. EPA cellulosic RIN credits to  
8 help with their obligation. Is there an upper limit or  
9 is U.S. EPA just making those available to the removed  
10 portion of the requirement? I mean is there some limit  
11 to how much companies can just purchase from U.S. EPA to  
12 comply with that element?

13           MR. BRAUTIGAN: Okay, the way it works is when  
14 we go to file our compliance for 2011, if we are - we  
15 can either run a cellulosic deficit, or we could buy a  
16 cellulosic allowance from the EPA for \$1.13 for each  
17 allowance. So we know what the price is ahead of time,  
18 only obligated parties can buy them, and they can only  
19 buy them when they're doing their submission, and so you  
20 have the choice of either running a deficit and hoping  
21 to make it up in the following year for that facility  
22 because the facility can only run a deficit for one year  
23 in a row, or going ahead and writing out a check to - I  
24 think it's going to be the U.S. Treasury - for \$1.13 for  
25 every cellulosic RIN you're short. The problem is the

1 celluloseic - yeah, does that answer your question?

2 MR. SCHREMP: I guess my question is, can you do  
3 that indefinitely? I mean, can all the companies do  
4 that indefinitely for a billion gallons, two billion  
5 gallons, four billion gallons?

6 MR. BRAUTIGAN: Yeah, when they issued the  
7 celluloseic - I think the term was waiver - when they  
8 reduced the volume down - I thought it was 6.5 million  
9 this year - the Regulations state that they will also  
10 offer up to 6.5 million allowances, so, in theory, the  
11 industry as a whole could all buy celluloseic allowances  
12 and not blend one drop of celluloseic ethanol, even if  
13 celluloseic ethanol was out there and available.

14 MR. WENG-GUTIERREZ: So with that, we're going  
15 to move into our Refueling and Recharging Infrastructure  
16 topic. I just wanted to say a couple of words here.

17 In California, we have about 10,000 locations  
18 where we dispense about 20 billion gallons of  
19 transportation fuel a year. With the introduction, or  
20 increased use of renewable and alternative fuels, we're  
21 going to have to develop other types of retail station  
22 infrastructure to ensure that we have sufficient  
23 distribution throughout the state and we want to make  
24 sure that those new stations are located in strategic  
25 locations and that they are optimally used to make sure

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1 that they are successful in their venture. However,  
2 fuel supplies and vehicle populations are necessarily  
3 interrelated elements to this, and we need to make sure  
4 that, again, we are implementing the development of the  
5 infrastructure in a strategic way that optimizes the  
6 use, given our projections of vehicles and where they  
7 will be located.

8           So there are some challenges in trying to do  
9 that, and that would be our goal is to make sure that we  
10 try to optimize the system and have a very strategic  
11 method, but I think people should be talking about how  
12 we should go about doing that and certainly some of the  
13 questions that we had in the Addendum, or the Agenda --  
14 the Supplemental Agenda -- speak to those. There are a  
15 number of issues that need to be addressed at the retail  
16 distribution level, some of those were discussed about  
17 E85 and the pricing, how you recover the costs for  
18 different things for the actual projects developing out  
19 there, and those should also come to light hopefully in  
20 the discussion here about retail infrastructure.

21           I also wanted to mention, the California Energy  
22 Commission and the Emerging Fuels and Technologies  
23 Office has an AB 118 Program. They are going to have a  
24 couple of workshops coming up, there is a May 23<sup>rd</sup>  
25 workshop, I believe, it's the second advisory panel

1 meeting on the Draft Investment Plan. AB 118 is a  
2 program where the Energy Commission as a whole is  
3 funding and subsidizing certain infrastructure  
4 developments. So I think there is a tie-in there, I  
5 think if there are opportunities, you know, if anybody  
6 is interested, they may want to attend that, look at the  
7 Investment Plan, and participate in that, as well.  
8 There are a couple of other workshops that are going to  
9 be presented in remote locations, as well, I think there  
10 is one in San Francisco and one in Long Beach coming up  
11 at the end of May and June, as well. So, I wanted to  
12 mention that.

13 I guess the next question is, is Tim Carmichael  
14 here? He is here, great. So I'm going to have Tim  
15 Carmichael come up, he'll be discussing, I think,  
16 natural gas.

17 VICE CHAIR BOYD: Tim, just before you start and  
18 kind of - well, go ahead with what you were - in  
19 conclusion of the last item, I just wanted to point out  
20 for those who are interested in ethanol that, in the  
21 Investment Plan, and for our AB 118 Program, we're  
22 having a very unusual experience this year in the  
23 California Legislature; oftentimes when I walk into the  
24 Offices of a Legislator, usually from a farming part of  
25 the state, I get hit with the following comment: "I hate

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1 ethanol." That trickles down to - and it's a product of  
2 the allegations that - and, you know, most of our  
3 ethanol comes from corn, therefore the allegations that  
4 the ethanol demand of the nation or this state are  
5 putting pressure on the price of corn, and thus on the  
6 price of animal feed, and thus impacting agriculture  
7 very excessively, they argue. And they have been  
8 trolling the halls of our Capitol for weeks and months  
9 now, with that message, which has put a lot of pressure  
10 on this agency's tiny little AB 118 Program that lends  
11 assistance with lots of costs, so to speak, or  
12 requirements for future progress on the aid that we have  
13 been giving to the restarting of some California corn to  
14 ethanol plants, which has a lower carbon footprint than  
15 ethanol produced in the Midwest. But the program is on  
16 the ropes, quite frankly, because of that legislative  
17 pressure and we seem to be in enough trouble with the  
18 Legislature in other arenas and areas this year that it  
19 makes it a very difficult bit of leverage, so I just  
20 wanted to pass that on to folks, this is not a hearing  
21 on ethanol or corn, but there are a lot of folks out  
22 there - we just finished a lot of discussion about  
23 ethanol, and I thought I would share our woes with you,  
24 just to know that you aren't the only ones facing issues  
25 relative to the RFS Standards and what have you - to the

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1 point that the California Secretary of Agriculture and I  
2 have had a lot of discussions about the high probability  
3 of us having a separate workshop hearing or something on  
4 the agriculture energy nexus and what it means, food vs.  
5 fuel, waste-to-fuel, etc. etc., so just to highlight  
6 that perhaps later this summer a non-IEPR-related  
7 subject, but all these issues are connected, so you  
8 can't help it but - I'm frankly getting tired of getting  
9 beat up over the fact that we put a piddling amount of  
10 money into keeping some California investment alive and  
11 running, employing California people, and returning  
12 California taxes in a few communities for a tiny amount  
13 of ethanol, instead of importing it all from the  
14 Midwest, particularly when it has a better carbon  
15 footprint; but other ramifications of that, as I  
16 indicated, are the politics of the moment. So we need  
17 to shine more light on that issue because I frankly  
18 don't know whether - because there are lots of opinions,  
19 so we're going to give lots of people a chance to  
20 express opinions on that subject. So, enough said about  
21 ethanol - more than I even intended to say, but we're  
22 all one big happy family here, so why not?

23 MR. WENG-GUTIERREZ: And, actually, as a follow-  
24 up comment to that, there's another workshop dealing  
25 with AB 118 where they're going to be discussing the

1 benefits and that is part of the IEPR process, as well,  
2 so that should be - the workshop should be some time  
3 later in the summer, and the topic is the benefits  
4 associated with the Investment Plan and those dollars  
5 being invested should be incorporated into the IEPR, as  
6 well, so...

7 MR. CARMICHAEL: Good morning. Tim Carmichael  
8 with the California Natural Gas Vehicle Coalition. Let  
9 me just start with a shot back. I was a little  
10 disappointed in your presentation of that May 23<sup>rd</sup>  
11 workshop, the opportunity to spend all day with 20 or 25  
12 Clean Fuel advocates doesn't excite you? I hope most of  
13 the people in the room will be there, it should be a  
14 good review of the next draft of the plan; I'm an  
15 Advisory Committee member, so plugging that meeting.  
16 Thank you very much, Commissioner Boyd, Commissioner  
17 Peterman, for the opportunity to be here and share a few  
18 thoughts on what's going on with the natural gas sector.

19 You know, there were a few dour comments made  
20 before me and I, actually, am going to bring a lot more  
21 positive news, I think. There's tremendous opportunity  
22 and tremendous energy in the natural gas sector right  
23 now. One example of that, there was a conference on  
24 Alternative Fuels and Alternative Fuel Vehicles in Long  
25 Beach last week. They anticipated about 800 attendees,

1 they had 1,300, and a good chunk of them were fleet  
2 operators looking at natural gas, among other  
3 technologies and fuels, and that event included as much  
4 buzz and enthusiasm about alternative fuels as I think  
5 I've seen in a decade or more.

6 VICE CHAIR BOYD: Some of us were conspicuously  
7 absent due to an inability to travel anywhere in the  
8 state.

9 MR. CARMICHAEL: Well, fortunately -

10 VICE CHAIR BOYD: And a couple of our staff went  
11 on their own hook to that.

12 MR. CARMICHAEL: Indeed. It was nice to see a  
13 few State employees there on vacation. So, through the  
14 natural gas industry lands, we're making progress every  
15 day. On the vehicle front, you've got every major truck  
16 manufacturer in the country producing a natural gas  
17 option, at least one, and selling vehicles today; you've  
18 got at least five companies building stations here in  
19 California, you've got now - we're quickly approaching  
20 150 refueling stations, public access refueling  
21 stations, in the state with, I think, just over 400  
22 total stations, including the private fleets. And that  
23 little directory I handed out is last year's version of  
24 the stations available for public access here in  
25 California.

1           That said -- oh, and I also want to say, the  
2 light duty vehicle progress has been a little bit  
3 disappointing here in California and I recently had an  
4 opportunity to talk to Commissioner Boyd about this --  
5 Honda continues to sell vehicles, you're seeing some  
6 movement from General Motors, some movement from Ford,  
7 especially targeting the fleet markets, but not nearly  
8 the activity that those companies are enjoying in Europe  
9 and Southeast Asia and other parts of the world. So,  
10 I'm still hopeful that we're going to see, you know,  
11 considerably more models available in the light duty  
12 sector here in California in the near term. As I told a  
13 number of people in the room, I thought it would have  
14 happened by now, but I still see a tremendous potential  
15 there, especially if the projections are right, that the  
16 prices of the alternative fuels remain relatively the  
17 same of what they are today, or if petroleum prices go  
18 up even more than they have.

19           Putting this progress in context, though, I  
20 think is important. At this conference I attended last  
21 week, Daimler Trucks reported that in 2010 they sold -  
22 oh, and I should take a step back - I'm going to give  
23 some overview comments and then I'm going to address  
24 some of the specific questions staff gave me for today.  
25 So, Daimler Trucks in 2010 sold 975 alternative fuel

1 trucks in the United States. This year, in the first  
2 quarter, they sold 1,000 alternative fuel trucks, so in  
3 the first quarter this year, they sold more than all the  
4 alternative fuel trucks they sold in 2010. But, they  
5 will still sell something north of 110,000 diesel trucks  
6 in the United States this year.

7 Peterbilt, another large truck manufacturer in  
8 the country, will sell somewhere between 220,000 and  
9 240,000 trucks this year; they're planning for at least  
10 five percent of those to be natural gas, but they are  
11 prepared for that number to go up to as high as 20  
12 percent of their sales this year. Jumping subjects, CEC  
13 funding, you mentioned the AB 118 program, the CEC  
14 funding in California has been tremendous. The natural  
15 gas sectors enjoyed a good chunk of the funding to date  
16 for vehicles, for infrastructure, and for biomethane  
17 development, and it has made a tremendous difference in  
18 a small, but emerging market for natural gas as a  
19 transportation fuel in California.

20 On the infrastructure money, there is still a  
21 struggle for our members and others that are seeking  
22 public funding from CEC for infrastructure projects.  
23 I'm talking about refueling projects, not so much the  
24 biomethane development. And the specific challenge,  
25 which Commissioner Boyd is well aware of, has been the

1 CEC's approach to CEQA relative to getting these funds  
2 out the door in a timely way. We greatly appreciate the  
3 efforts that have been made to streamline the vehicle  
4 funding and we're hopeful that that's going to be a  
5 tremendous success this spring and summer, and we're  
6 further hopeful that that success can roll over into  
7 infrastructure funding with a more streamlined process  
8 there.

9 Another challenge I want to mention with the  
10 public funding that a number of our members have  
11 experienced is, in the distribution, it's often the case  
12 that the funding is available for a short window of  
13 time, often the first couple of months of the year,  
14 which is fine if you've got projects ready to go at that  
15 time of year. But what we're starting to see is  
16 companies that, you know, get a project ready in July or  
17 August, are waiting with that project, whether it's  
18 vehicles or infrastructure, for that next cycle of  
19 funding assistance to try and seize a piece of that  
20 public funding pie.

21 So our suggestion on this piece, and I'll bring  
22 this up again in the AB 118 context, is it might be  
23 worth looking at a 50/50 split on funding pots, six  
24 months apart each year, in your fiscal year funding  
25 cycle, so we would continue to see a smooth flow of

1 projects year-round. I think that's better for the  
2 industry, I think it's better for the consumers.

3           Public access -- one of the issues that's been  
4 coming up relative to the infrastructure funding for  
5 natural gas is to what extent should public access be a  
6 requirement. Our membership, you know, 25, almost 30  
7 companies now operating in California, all believe that  
8 public access should be a core component of every  
9 refueling project that gets CEC funding at any  
10 significant level. You know, it's public funding going  
11 to support infrastructure that we want in this state,  
12 but public access needs to be part of those projects.

13           The last thing in my general comments that I  
14 want to flag is something that - actually, two more  
15 things - is that the Federal Natural Gas Act, I'm sure  
16 this is on the radar screen of many people in the room  
17 and CEC staff, but I'm not sure the Commissioners are up  
18 to speed on this, so there's been a run at this the last  
19 few years, and that's basically an incentives package at  
20 the Federal level to support natural gas vehicles and  
21 refueling infrastructure. This year, unlike years in  
22 the past, we have more than 150 co-authors on the bill,  
23 almost an event split, Republican and Democrat. That is  
24 the strongest showing this type of incentives package  
25 has seen in Congress, period. So, we are more than

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1 hopeful that there will be success this year in getting  
2 such a package through. Some highlights of this  
3 package, and then how it ties in to California. If it  
4 passes as drafted, roughly \$3 billion in incentives in  
5 the form of tax credits over the next five years. The  
6 vehicle portion would cover up to 80 percent of the  
7 incremental cost of a natural gas vehicle compared to  
8 its diesel or gasoline counterpart, with hard caps on  
9 how much could be spent per vehicle, between \$7,500 and  
10 \$64,000, depending on the size of the vehicle.

11 VICE CHAIR BOYD: Tim, 80 percent of the cost?  
12 Or 80 percent of the incremental -

13 MR. CARMICHAEL: Incremental cost.

14 VICE CHAIR BOYD: -- sorry, thank you.

15 MR. CARMICHAEL: With a cap of \$7,500 to  
16 \$64,000, depending on the size of the vehicle. And  
17 then, on the infrastructure size, tax credits ranging  
18 from - actually, tax credits of up to 50 percent or  
19 \$100,000 per station. And then, for home refueling, an  
20 increase in the existing program from \$1,000 per home  
21 refueling unit to \$2,000 per home refueling unit. Why  
22 is that relevant to California? It's relevant to  
23 California because, today, the CEC's 118 program is the  
24 largest all-fuels funding program in the country. If  
25 this Gas Act passes sometime this summer, it will have a

1 tremendous impact on the near term future of natural gas  
2 and transportation fuel in this country, but it won't  
3 mean that CEC funding will no longer be necessary. What  
4 it will mean is that CEC, through the AB 118 program,  
5 will need to be strategic in the - let's say more  
6 strategic - when you've got nobody else giving funding,  
7 everywhere you give it, it's valued. When you've got a  
8 big contribution coming from the Federal Government,  
9 it's going to be more strategic for CEC to look for  
10 where the holes are and where can CEC leverage its  
11 funding, either through a matching effort with the  
12 Federal program, or cover the types of projects that the  
13 Federal Government is not going to be covering with this  
14 tax credit program.

15           The last thing I want to mention is a general  
16 overview of where things are going and things to watch,  
17 is that the biomethane sector, which people are  
18 increasingly calling "Renewable Natural Gas," that at a  
19 conference late last year here in California, there was  
20 an estimate that the potential for the renewable natural  
21 gas in California relative to transportation is as much  
22 as 17 or 18 percent of the heavy-duty fuel supply - 17  
23 or 18 percent of the heavy-duty fuel supply in  
24 California. That is an important number, but it's also  
25 important to think about could that, you know, pot of

1 gold if you will, be used more beneficially or more  
2 strategically if it were blended with fossil fuel  
3 natural gas, just looking strictly at carbon. You've  
4 got your fossil fuel natural gas, you know, 20 percent  
5 better than diesel, something in that ballpark. You've  
6 got renewable natural gas, you know, one of the cleanest  
7 if not the cleanest fuel available in the current  
8 assessment of alternative fuels; if you blend them and  
9 you get something that is 50 percent better, and you  
10 touch a third of the fleet or more in California, that  
11 may be the most impactful way to use that fuel. I'm not  
12 saying that is the only way to go, but it's definitely  
13 something that CEC should be looking at and thinking  
14 about as the biomethane market continues to develop.

15 To the staff's specific questions, one of the  
16 issues raised, and these kind of blend together, is the  
17 capacity of the refueling infrastructure in California  
18 today for natural gas and, you know, the fact that some  
19 of that refueling infrastructure is getting old.  
20 Believe it or not, we have been going at this, or some  
21 of the companies in the room have been going at this for  
22 more than 15 years now, and some of that infrastructure  
23 has not been upgraded yet.

24 As it relates to CEC, it's an issue to watch.  
25 You know, whether it's slower fueling because the

1 compressors are small, or the pressurization is for a  
2 lower pressure than the current tanks or - oh, sorry -  
3 the tank certifications on vehicles is for a lower  
4 pressure than the new higher capacity, higher pressure,  
5 refueling stations. There are some issues with this  
6 aging infrastructure, and there is a need to upgrade,  
7 but most of our membership believes that that is  
8 something the market will take care of. The people that  
9 purchase those stations are going to upgrade them to  
10 remain competitive and, for the most part, the better  
11 use of CEC funding is for new infrastructure, to get  
12 more new stations out there, sooner.

13           Another question about historic patterns of  
14 purchasing and use of natural gas vehicles, and what do  
15 we see as far as future trends. The rising cost of  
16 petroleum is the number one, number two, and number  
17 three issue on my list of things to pay attention to.  
18 As long as petroleum stays somewhere in the ballpark  
19 that it is now, or goes up higher as the number of more  
20 highly paid financial analysts are predicting, the  
21 natural gas is going to be a very appealing alternative,  
22 and I'll come back to that point a couple of times.

23           Today, because of the price of gasoline and  
24 diesel, many fleets in the country, not just in  
25 California, but many fleets in the country, are driving

1 less. Many fleets are taking fuel conservation much  
2 more seriously than they have in the past. A number of  
3 fleets are reporting about their driving training  
4 classes, and we actually know a couple of people that  
5 their business is training fleet truck drivers how to  
6 drive more efficiently because the price of fuel is such  
7 a factor in the operations for so many businesses these  
8 days. It's also led a lot more fleets on a national and  
9 local scale to look at natural gas and other  
10 alternatives as a very viable alternative. I think,  
11 this year, you will see - we have seen - and it gets  
12 good attention, but maybe not enough, companies like  
13 waste management, like UPS, using natural gas and other  
14 alternative fuels increasingly, but I think you are  
15 going to see a lot more of the middle level operators  
16 and small operators do their proof of concept, their  
17 sampling, this year and the next year, bringing in two,  
18 three, five trucks, running them on a multi-month period  
19 to show not only their Management, but their truck  
20 drivers, that this is going to be a really viable  
21 option. And that is an important step towards  
22 significant purchase, whether it's a 50-truck purchase  
23 or a 200-truck purchase over the next few years, that is  
24 going to be, I think, an area of active work for a  
25 number of fleets in California this year.

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1           You're also seeing quite a bit of attention paid  
2 to fuel economy technologies, not just with diesel, but  
3 with natural gas, whether it is hybridization or dual  
4 fuel technologies, where you get the benefits of both  
5 fuels to maximize the efficiency, as well as the  
6 environmental benefits of the combination of fuels and  
7 technologies. One example that was given to me recently  
8 is a lot of the heavy-duty truck operators historically  
9 have averaged about five miles per gallon. But with the  
10 combination of technologies and driving skills, improved  
11 driving skills, they're upping that to seven miles a  
12 gallon. You know, when we're talking about 40 miles a  
13 gallon for some of the passenger cars, or even 50 miles  
14 a gallon, it seems like such a small number, but if  
15 you're driving 100,000 miles a year, that increment from  
16 five to seven is very significant and it's very much on  
17 the minds of fleet operators in the state.

18           We anticipate that overall consumption of  
19 transportation fuels is going to stay relatively low for  
20 the next couple of years assuming prices stay close to  
21 where they are today, but when the economy starts to  
22 recover more robustly, we expect a significant, if not  
23 dramatic growth, in alternative fuel use in the state.  
24 One example that I want to leave you with, again, from  
25 this conference last week, UPS's National Fleet Manager

1 spoke at this conference and he said that he would not -  
2 he said he can see his company buying 100 percent all  
3 fuel vehicles by 2015, that is, all new vehicle  
4 purchases for UPS could be - 100 percent of them could  
5 be alternative fuel by 2015. That's less than four  
6 years away. And I think it is an important statement  
7 about how some of the largest fleets in the country are  
8 looking at the cost of petroleum, the projection for the  
9 cost of petroleum, and the need for them to make some  
10 dramatic changes in the way they run their fleets. With  
11 that, if there are any questions, I would be happy to  
12 answer them, either from you or from the staff, and then  
13 I'll see you in a couple of weeks on the AB 118 context.

14 VICE CHAIR BOYD: Thank you, Tim. I don't have  
15 any more questions.

16 COMMISSIONER PETERMAN: I don't either, although  
17 it was very interesting. Thank you for the update, and  
18 it's a bit more optimistic.

19 MR. WENG-GUTIERREZ: With that, I'm going to go  
20 ahead and ask Tom to come up and, actually, at this  
21 point if I could have the panelists also come up and sit  
22 at the front desk, grabbing their little name tags, that  
23 would be great. I think we have a little slide. Just,  
24 as we're getting everybody to come up, I would ask that  
25 everyone, if you have a chance, I had a slide that had

1 some questions in there about the electricity and all  
2 the other components, as well, so we might want to look  
3 back from time to time throughout the day at the  
4 questions that we had in our addendum to, again, refresh  
5 our memories as to what we're trying to gather from the  
6 speakers today. Hopefully, again, those questions will  
7 be addressed to a certain extent in those topics.

8 MR. TURRENTINE: Thank you, Malachi. Thank you,  
9 Commissioner Boyd and welcome, Commissioner Peterman,  
10 and audience, thank you.

11 Today I'm actually going to speak for Dr.  
12 Michael Nicholas, who will be the person who really will  
13 become the PHEV Center's expert in these infrastructure  
14 issues; he is in Washington, D.C., also talking about  
15 infrastructure there.

16 So, the PHEV Center, thanks to the Energy  
17 Commission, is now three and a half years old, has been  
18 working on issues relative to plug-in hybrids, and now  
19 focusing also on battery electric vehicles and looking  
20 at this particular area of infrastructure; we have a  
21 team who is working on this, as I mentioned, Dr.  
22 Nicholas and two other doctoral students and  
23 researchers, and a whole group of students also working  
24 on this project. And, in the future, we'll be working  
25 closely with Ecotality in a San Diego Project, and

1 collecting tremendous amount of data, it's an exciting  
2 time, a lot of vehicles. Just to point out some things  
3 in the picture here, most of our research over the last  
4 few years has been based on conversion vehicles. You  
5 see in the picture in the background, we have converted  
6 plug-in hybrids, we've done projects with converted Mini  
7 Coopers, working with BMW. It's a big moment, but it's  
8 an exciting moment to have brand new OEMs, vehicles  
9 coming out on the market, as we all know, Nissan, GM,  
10 and other products coming down the pike. So, we'll be  
11 working with those, but the results I talk about today  
12 are based on these conversions and research over the  
13 last two to three years.

14           So, just to start, this is a difficult issue in  
15 some ways. I had a chance to travel and visit a number  
16 of cities around the world and look at infrastructure  
17 for electric vehicles in the last three years, and talk  
18 to a lot of people, but we don't have any examples right  
19 now, we're in the middle of an experiment. And also,  
20 trying to build an infrastructure all at the same time  
21 raises some challenges, how do we do that? We have a  
22 lot of questions, still, you know, what's the right  
23 ratio of what we call home, workplace, and public  
24 charging, these locations. It's different than your  
25 gasoline network, you know, people as we know are going

1 to have to have chargers at home, they could have them  
2 at any parking place, anywhere, but which parking places  
3 are the right places to put charging? Also, fast charge  
4 stations will be a little more like gas stations. How  
5 much of that network do you need? And for that market,  
6 do we think we need to accelerate the market? Is it  
7 necessarily to accelerate the market? And where do we  
8 put it, exactly? What are the details? What are the  
9 exact locations? You know, you have to cut some  
10 concrete out there and make some investments and, as you  
11 do that, you're making some commitments - is that the  
12 right place? How do you know exactly what are the right  
13 places? Do we encourage free charging? We did back in  
14 the '90s, there was a lot of free charging and dedicated  
15 spots, is this sort of an extra bonus for PEV drivers?

16 Do we need fast chargers? In the '90s, we  
17 didn't talk about it, now we have fast chargers, we have  
18 DC fast chargers, and in the future probably some Level  
19 3 chargers. How important are these? How are they  
20 going to fit into our grid system, and how many might we  
21 need? They are more expensive. And what will become  
22 that right mixture of Level 1, Level 2, and fast  
23 charging? And do we need to provide chargers on our  
24 long distance corridors like I-5?

25 There are a lot of opinions about this right now

1 and, as we move forward, we're in the experimental  
2 stage, it's okay to have these opinions, yet some are  
3 saying we need a ubiquitous network, we need to just put  
4 as much out there as we can, move quickly, you know,  
5 sort of a "Build it, they will buy," that this will  
6 encourage the market and move the market forward faster.

7           Some say Government should not be involved in  
8 this and that this should be a private sector, just let  
9 the risk develop the network, and that will be more  
10 efficient. A lot of people are talking about focusing  
11 on regional development because battery electric  
12 vehicles have a limited range and probably are not as  
13 practical on long-distance trips, so there is a focus on  
14 developing urban regional markets and not paying as much  
15 attention to rural areas. And be data driven. Plan  
16 this out. Do a better job of planning. Be careful.  
17 Monitor the use carefully.

18           So I'll go ahead and give the punch line, that  
19 last one, you know, being a research group, of course,  
20 we're exploiting that data-driven, we're very interested  
21 in data, and we like to use data to make decisions and  
22 design. And we're very interested in regional design,  
23 we recognize the limited range issues and have been  
24 doing a lot of work with electric vehicle drivers and  
25 plug-in hybrid drivers, we're very interested in that

1 regional design issue.

2           We do see the home base as the core of the  
3 network and we use a number here, about 80 percent, but  
4 it's more than that, probably we've said 90 percent,  
5 also, as the demand for electricity will come at a home  
6 base. And when I say "home base," I mean households,  
7 but also businesses, where that vehicle is parked at  
8 night, that fixed parking spot at night, that's where  
9 most of the demand is going to be for the electricity.  
10 Some of you say, "Well, but what about a city like San  
11 Francisco?" And I'll talk a little bit more about that,  
12 where they don't have as much parking fixed. We also  
13 need emergency locations, hospital, transit centers,  
14 government locations, schools, places that people need  
15 to get to, we need to have charging there.

16           Work place is an interesting area - how much  
17 work place charging should there be? We need ways to  
18 help businesses assess what the market will be for their  
19 employees, for their own fleets, and for visitors and  
20 clients. What will that charging need to be like?  
21 Public locations beyond work places, parking lots,  
22 shopping centers, what should it be? I talk about  
23 recreational locations in regional shopping in our work  
24 a lot. And then, fast chargers, if we bring fast  
25 chargers in, where should they go? What are the best

1 locations? This is very much a research - we're in a  
2 research phase. We don't know, we don't have the data  
3 telling us exactly how those will be used and how much.  
4 And so we need a rigorous monitoring of this new  
5 network, it's, as I said, we're in a research phase, so  
6 we need to be monitoring just how these chargers are  
7 being used, how much they're being used, when they're  
8 being used, who is using them, we need to know this to  
9 make good decisions in the future as we roll out this  
10 infrastructure.

11           If you follow this data-driven approach, you  
12 have to understand the market - how is it going to  
13 develop? How many vehicles are going to roll out? We  
14 sort of know a few thousand vehicles are going to be on  
15 the road, manufacturers are going to be selling in the  
16 next few years. Who are those people? Where are they?  
17 Who has the ability to buy these vehicles? Who has a  
18 place to charge?

19           Here is a chart that Joshua Cunningham and I put  
20 together sort of shooting at the future, this  
21 forecasting is a difficult business, there are a lot of  
22 variables. We put together a nice - some ambiguity in  
23 the chart, but looking sort of at the low numbers here  
24 are what the ZEV program is pushing the state towards,  
25 the upper limit is what some of our hopes are for this

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1 marketplace. But, certainly, these sales as these grow  
2 will determine how this - and that mixtures of sales,  
3 how many of those are going to be battery electrics, how  
4 many of those are going to be plug-in hybrid 10's, how  
5 many are going to be plug-in hybrid 40's, and how will  
6 that play out in the use of infrastructure?

7           As I said, we expect mostly that electricity is  
8 going to come at night time from home-based, and that's  
9 going to be more difficult than -- cities like San  
10 Francisco and Berlin are a couple we know about that are  
11 going to be trying to find places for people that to put  
12 chargers are difficult. And law will control all of  
13 that. For example, in Berlin, you can't just put a  
14 charger on a sidewalk, it's not legal. You can't  
15 designate a piece of parking for somebody separate from  
16 the rest of the population, you can't separate that out.  
17 So we see houses sort of on the left, the nice three-car  
18 garage, that's going to the first buyers, the income,  
19 they've got the right place, the right electricity  
20 panel.

21           We just finished a big project and, in the next  
22 week we'll be handing out the final report on this BMW  
23 project, and we'll be having a lot to say about how  
24 people use those BMW Mini Coopers.

25           This is just a couple of slides from that work,

1 to talk about. We do know that, in that project, BMW  
2 drivers did not have home charging in Los Angeles, most  
3 of them didn't - in our interview work, we don't ask  
4 them specifically about - we try to let them lead us in  
5 our work, and people didn't talk about needing charging  
6 in too many places beyond home. They had a few places.  
7 And they were kind of surprising to us, when we asked  
8 them where they wanted charging, they didn't say  
9 necessarily at shopping centers. A few people did say  
10 at work, a lot of them said favorite recreation areas  
11 and even a second home, a few people, but also ability  
12 to visit family and friends. When you're doing  
13 transportation research, you realize that sort of  
14 travel, which is beyond the range of electric vehicles,  
15 takes you to these recreation and shopping locations.

16 So we're moving forward in our research,  
17 defining charger markets sort of in three ways, sort of  
18 a primary market being those, what we call "low hanging  
19 fruit," those households which are easy to install, that  
20 probably the income will be buying these first vehicles  
21 in the next six years. They have a fixed nighttime  
22 place the car returns to every night. The secondary  
23 markets do have a fixed place, but there's going to be  
24 some costs involved, probably, cutting concrete, putting  
25 in conduit where a lot of the expenses are.

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1           Tertiary markets are those which there is no  
2 fixed parking for a car at night; this is going to be  
3 difficult. How do we provide for these people? This is  
4 somewhere off in the future, but we do need to be  
5 thinking about this down the road.

6           Our data in the past from surveys for the United  
7 States and California and Northern California shows that  
8 about 50 percent of new car buyers probably have a good  
9 chance of putting in some sort of charging where they  
10 park their car at night, at least within 25 feet. So,  
11 some trenching, maybe. And then, work places that next  
12 priority, said this can have significant benefits, some  
13 of our research on plug-in hybrids show that you could  
14 double the utility factor or the amount of electricity  
15 that will be used by these vehicles if you put in  
16 workplace charging, so the workplace can be important if  
17 we want to reach some of our goals for using electricity  
18 instead of gasoline. Workplace charging could be used  
19 by a lot of people who visit workplaces, not just the  
20 employees and not just the fleets.

21           We also believe in, again, this data driven  
22 approach. We need to work with businesses to understand  
23 how this would play out and who are using those so they  
24 don't just sit in the back in somebody's parking lot  
25 after investment and we don't know why they're not being

1 used.

2           Again, a regional public network. We need a  
3 safety net, we need to expand the activity space of  
4 drivers, this is the big benefit of putting in some  
5 charging from talking to electric vehicle drivers, not  
6 for PHEV drivers, really, although there is some of  
7 that, it's to expand their activity space, not to give  
8 them charging at a shopping center that is just two  
9 miles from their home, but somewhere that allows them to  
10 expand. And fast charge may be a big solution for that,  
11 also.

12           Here, we look at some of the research we're  
13 doing, just to give you the flavor of how we're going to  
14 try to answer some of these questions. Here is just a  
15 very detailed approach to GPS travel data on 10  
16 households, actually PHEV drivers, and looking at where  
17 they drove over a month in great detail and where they  
18 probably would charge if they used fast chargers, where  
19 would you locate those. It kind of shows you the type  
20 of research we're doing. Here is some interesting data  
21 that, again, becomes important if we look at fast  
22 chargers networks. We can make assumptions about how  
23 they'll be utilized, but this shows you that, you know,  
24 it's not going to be even across the days of the week,  
25 for example, it's not distributed - Tuesdays probably

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1 not as much as Fridays. Friday afternoon, everybody is  
2 going to want that fast charger given what we see from  
3 travel data. So, how do you build a network when you  
4 have such uneven demand?

5           We look at corridors. A lot of people have  
6 talked about putting in corridors in the past, we have  
7 just done a recent evaluation of Highway 99 and I-5, of  
8 course, there is a lot of population around I-99. I-5,  
9 there's hardly anyone along it. If you did some just  
10 simple energy analysis, we'd find a Leaf, we'd need six  
11 charges driving 70 miles an hour. Actually, you could  
12 drive 55 miles an hour and you could do four charges,  
13 given that higher speeds use up all the energy, you get  
14 there at the same time. You would need to drive 55 or  
15 70, but as most of you know, you'd probably get run over  
16 at 55 if you're driving down I-5.

17           So that's just a start, I hope that the  
18 panelists can take some of that overview and it'll get  
19 things started.

20           VICE CHAIR BOYD: Thanks, Tom.

21           MR. WENG-GUTIERREZ: Thanks, Tom. So I think  
22 we're just going to jump right into the Panelists, then,  
23 and we'll hold the questions, all the questions, until  
24 after all the panelists have had a chance to speak. So  
25 I think the first Panelist is Richard Lowenthal.

1           MR. LOWENTHAL: Do you have some slides up there  
2 for me?

3           MR. WENG-GUTIERREZ: Yes.

4           MR. LOWENTHAL: Great. Thank you very much.  
5 I'm Richard Lowenthal. I'm the Founder and CTO of  
6 Coulomb Technologies. So, we provide software for  
7 charging networks and hardware, as well, that we use and  
8 other hardware providers use. The message of this  
9 slide, though, to me, is that we are seeing  
10 infrastructure take-up by some of the more difficult and  
11 challenging applications like the multiple dwelling unit  
12 based on having a financial model. So, that is, for  
13 instance, I just did an announcement in New York City at  
14 a 4,000-unit apartment building where they put in  
15 charging infrastructure based on sort of a vending  
16 machine mentality, that you buy this infrastructure, you  
17 charge drivers for using it, and based on that, the  
18 apartment association could justify it. So, the message  
19 being there that we need to allow capitalism to set - to  
20 have some of this growth. We appreciate our CEC AB 118  
21 grant and that's helped us get going here in California,  
22 but without a method of paying for ongoing costs, places  
23 like condominium associations and apartments will not  
24 put in infrastructure.

25           Similarly, at workplace, they don't want open

1 charging, they want some control, and so we see that -  
2 I've got some other messages about workplace, but we are  
3 quickly shifting from government subsidy to capitalism  
4 as driving the growth of infrastructure. Next slide,  
5 please.

6           So here, I just wanted to bring up some things,  
7 some surprises we've learned. We shift now 4,000  
8 stations to over 700 customers and I just wanted to  
9 bring some news back from that world. First of all,  
10 we're seeing PHEVs charge twice as much as BEVs, and for  
11 a lot of people, that's a surprise. But we measure all  
12 of these things. Every person who charges on our  
13 network, we know where they charge, when they charge,  
14 how much they charge, so we're getting a lot of data.  
15 Obviously, PHEVs, generally speaking, have smaller  
16 batteries, and so we've got a new term now, "gas  
17 anxiety" as opposed to "range anxiety" because they hate  
18 running on gasoline, and we're talking primarily about  
19 Chevy Volt drivers, but they'll do anything to stay off  
20 the gasoline, the hybrid mode of the vehicle, and so  
21 they are all charging twice a day, they are all charging  
22 at workplace and while you sleep, which is consistent  
23 with an old study of Tom's from like 20 - well, 10 years  
24 ago - where they show that 80 percent of people want to  
25 charge twice a day of people with PHEVs. BEV drivers,

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1 on the other hand, charge a little bit less than once a  
2 day, so a very peculiar finding, and that's because they  
3 have relatively large batteries. If they think they can  
4 make it to their next commute, sometimes they don't  
5 charge. So, somewhat non-intuitive, but truth.

6           Next, we are finding - sorry, same slide -  
7 cities cannot give away electricity. Even though San  
8 Francisco announced yesterday that they will, for some  
9 period of time, they all know ultimately that it's a  
10 gift of public funds to give away charging services, and  
11 so they will need a billing model and that will need to  
12 be enabled.

13           Next, we're finding a very interesting thing in  
14 the workplace, which is that it looks as though the IRS  
15 is going to rule that giving away charging services to  
16 employees is compensation, so we've built now a product  
17 to measure the value of charging for employees at the  
18 workplace so that they can report that to the IRS,  
19 that's another peculiar finding.

20           And, finally, I'm on a NEMA committee that we're  
21 working somewhat diligently to get the National Electric  
22 Code to change, to require new garages that are built to  
23 require wiring for electric vehicles. About two-thirds  
24 of the cost of installation for EV infrastructure has to  
25 do with retrofit; that is, bringing the electricity to

1 the location. And so, we are trying to eliminate that  
2 problem through the National Electric Code. That  
3 amounts to about half of the cost of the infrastructure  
4 cost now that go into the fact that these garages are  
5 not ready, so the current kind of favored thing to put  
6 in the National language -- to put in the National  
7 Electric Code -- is that you have a conduit in every  
8 garage that you build that is adequate to bringing 220  
9 volts or 110 volts, so that you can charge a vehicle in  
10 your garage without an expensive retrofit, similarly if  
11 it's a carport, or whatever, when you build any garage.  
12 Next slide.

13           Okay, so this an important one which I think  
14 I've heard a lot of kind of misstatements or  
15 misunderstandings about here, even at the Commission.  
16 So, charging at work, generally speaking, is off-peak.  
17 People arrive at 8:00 in the morning, they generally are  
18 charged by 9:00. I show kind of worst case here that it  
19 takes three hours. You are still always off peak when  
20 you charge at work, and so there's a tendency of people  
21 to push away from workplace charging because they're  
22 worried about peak charging, but, indeed, it doesn't  
23 happen. People charge when they arrive at work in the  
24 morning and they're always done before peak happens.  
25 Contrary, and also somewhat surprising, is that charging

1 at home is generally on-peak, unless you have Smart  
2 Charging, so we would recommend that funding and rulings  
3 from the Energy Commission and the Public Utilities  
4 Commission, and others, require Smart Charging of some  
5 sort, so that people get off-peak when they charge,  
6 otherwise all charging will end up on-peak. And so the  
7 common knowledge is that, if you charge at home, you're  
8 always okay, but that's true as long as you wait until  
9 7:00 or 8:00 at night. I think, in San Diego, it's 8:00  
10 at night. In PG&E territory, it's 7:00 at night. But  
11 it is important that we don't put out too many dumb  
12 chargers, and most of the chargers that are going out  
13 now are dumb chargers, and so this problem is - we're  
14 exacerbating this problem by having bad infrastructure  
15 products going out on the market.

16 VICE CHAIR BOYD: So you're saying that it's a  
17 myth that the idea that we all have that people will  
18 drive home at the end of the work day, and then plug in  
19 maybe at the tail end of the peak, but really  
20 predominantly off-peak --

21 MR. LOWENTHAL: Yeah, that's a myth.

22 VICE CHAIR BOYD: -- you're saying they're going  
23 to be plugged in during peak hours.

24 MR. LOWENTHAL: They'll plug-in at 5:30 or so  
25 when they get home at night. Peak ends in - in San

1 Diego, peak ends at 8:00. In San Francisco, peak ends  
2 at 7:00. And so they're going to be on-peak unless we  
3 do something about it. Now, the cars have timers in  
4 them, smart infrastructure has timing in, we can  
5 implement -- what I would prefer to see is that we  
6 implement time of use incentives, incentive pricing, as  
7 San Diego Gas & Electric is trialing in their territory,  
8 to encourage people to get off-peak. Clearly, if we're  
9 off-peak, it's great for the utilities, it's great for  
10 the grid, it allows us to use more clean energy, and so  
11 we recommend it, but we're concerned about the  
12 complacency that people have, that if you charge at home  
13 it's always off-peak. Next slide.

14           Okay, so a few things. We believe right now  
15 that the leading impediment to EV adoption is not a lack  
16 of infrastructure, although that's what you read mostly  
17 in the newspaper, it's primarily the belief that the  
18 electric vehicles are too expensive. And indeed, that  
19 is, we think, way overstated. In any analysis we do,  
20 these cars pay you back in about four years because  
21 electricity is a cheap fuel, and gasoline is an ever-  
22 increasingly expensive fuel. And so, if you look at the  
23 Leaf, it takes about two years to pay it back; if you  
24 look at the Volt, it takes, I think, three and a half  
25 years to pay back. In the next slide, we'll see the

1 arithmetic here. Next slide.

2           And we're comparing the Volt to the Cruise,  
3 which is basically the same platform at Chevrolet, and  
4 the Leaf to the Versa, which are very similar platforms  
5 at Nissan, payback is very quick, over a six-year  
6 ownership of the car, the Volt pays back \$8,000; the  
7 leaf pays back \$7,300, and yet the only thing you'll  
8 hear in the public is that the cars are expensive. So,  
9 if we want to see people, or if we expect people to  
10 switch fuels over to electricity, we have to educate  
11 them about the low cost of operation on this fuel.  
12 Thanks very much.

13           VICE CHAIR BOYD: Thank you.

14           MR. WENG-GUTIERREZ: Thank you. So I think the  
15 next person we had on our list was Paul Heitmann.

16           MR. HEITMANN: Okay, thank you. My name is Paul  
17 Heitmann and I'm with Ecotality. And we're fighting the  
18 good fight, along with Coulomb. Also, one of my other  
19 hats, I'm on the New Jersey Board of - or, the Board for  
20 the Clean Cities Coalition. So, it was very interesting  
21 to hear about the natural gas because we've just  
22 implemented under a DOE grant four natural gas fueling  
23 stations in New Jersey, and are awaiting the data that  
24 we collect from that. So, it really is all about moving  
25 off of gasoline. I believe, on the electric side, the

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1 other point I'd like to make is, I was, as Richard was,  
2 participating in the MINI E Program, so it's always nice  
3 to see data, you know, having first-hand experience in  
4 that. My particular experience involved waiting for  
5 four months to get the permit to get the level 2  
6 charger, so I really learned what a level 1 electric  
7 vehicle lifestyle was all about.

8           Now, the EV project, the big project we're  
9 running right now for the Department of Energy, I just  
10 have some handouts here on the EV project, which I will  
11 give you. And for the people in the audience, you can  
12 visit the [TheEVProject.com](http://TheEVProject.com), that's all one word.

13           One of the questions that Tom raised in the  
14 presentation was what is the right mix of public and  
15 commercial charging with home charging? We do believe  
16 that most people, and I think it's very consistent, the  
17 early findings on the difference between the PHEV like  
18 the Volt, and the full EV, is very telling, that people  
19 have a battery, they want to use it, they want to charge  
20 it. It's almost incidental that they have the gasoline  
21 range extender. We are instrumented for a lot of data  
22 collection on the EV project and the reports that we've  
23 already developed with the Idaho National Labs are  
24 really geared at mining, right down to behavior  
25 differences of extended range electric vehicles like the

1 volt and all electric vehicles like the Leaf. So, I  
2 completely agree that it's all about data collection,  
3 and instrumenting, and understanding, and then adapting  
4 as you go, which is what we're doing.

5           So, relative to the mix of public charging, or  
6 public accessible charging and private, we feel that  
7 there is, maybe not immediately, but very quickly after  
8 the cars are adopted, most residents, if they can, will  
9 put in Level 2 charging. And that, I believe, was 80 or  
10 90 percent of the actual charging for the cars will  
11 happen at home. So, again, to echo Richard's comments,  
12 it's very critical that you've got the ability to defer  
13 that charging in an intelligent way, either through  
14 price signals or just straight timers, to move past that  
15 tail-end of the daily peak. Beyond that, the capability  
16 to instrument for utilities to control should include  
17 pushing a critical peak price signal because there are a  
18 couple advantages to that, 1) if there truly is an  
19 emergency situation in terms of supply of energy, the  
20 ability to override and message people that their use is  
21 going to be throttled is important, and secondly, it's  
22 starting to shift in the mindset and the behavior and  
23 response of people to be tuned into, "Hey, we're in an  
24 energy emergency, I need to do something different. At  
25 least I need to be aware that there is some difference."

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1 So, you can have time of use rates, but that critical  
2 peak override is really the messaging that comes in and  
3 starts to change societal behavior in the long run.

4           You'll see on the Facts at a Glance that we are  
5 deploying - we're supporting 8,300 vehicles, 5,700  
6 Nissan Leafs, and 2,600 Chevy Volts, so that's 8,300,  
7 and when it's all implemented, we'll have 14,000  
8 chargers. So, roughly, that's about 1.4 chargers per  
9 car. That's definitely on the high side of the public  
10 mix. Again, the experiment is really designed to see  
11 how are people going to use this, so they are all  
12 instrumented to see who uses what stations, how much of  
13 it do they really do at home, how much do they rely on  
14 the public. Most people, I think, estimate early on it  
15 will be about a 1.3 or 1.25, and over time, the more  
16 cars that are deployed, that ratio will go down to 1.1,  
17 1.2 maybe, and it will vary by region. But the real  
18 benefit of the public charging early on is the awareness  
19 and the visibility that people will see when they're  
20 going to the showroom to make the decision, in  
21 reinforcing their decision to buy electric. So, that's  
22 an intangible value that I think, on public charging,  
23 early on is very important. And as I said, we're  
24 deploying this nation - well, 18 cities, seven states,  
25 and we're instrumented to collect quite a bit of data

1 over the next couple years, so that will hopefully  
2 either dispel further myths, or reinforce best practices  
3 that we can leverage. Thank you.

4 VICE CHAIR BOYD: Well, thank you.

5 MR. WENG-GUTIERREZ: Thank you, Paul. Now we're  
6 going to go to Joel Pointon from SDG&E.

7 MR. POINTON: Good morning. I just wanted to  
8 share with you some of the highlights from the work that  
9 is going on in San Diego and some of the priority items  
10 that have evolved from that. In what we're looking at,  
11 the involvement with the Ecotality project, the  
12 involvement we have with the Multi-Unit Dwelling  
13 Outreach Program, we have existing EV Time of Use rates,  
14 which occurred back in the '90s. I have to say that the  
15 major challenge that we have facing us is the  
16 educational aspect with the stakeholders, the community,  
17 the public at large. And that's why you'll see that, in  
18 this lower section, it's the education portion that is  
19 critical. One of the things we do in every presentation  
20 that we do is we try to get people on the same page by  
21 giving them a basic vocabulary, giving them a glossary  
22 so that, when we use these terms, we at least are all on  
23 the same page, they have some appreciation for AC  
24 charging vs. DC charging, and some of the impacts that  
25 that has.

1           Getting the message across about the importance  
2 of the off-peak charging and whether we utilize off-peak  
3 charging will be the success or the failure for these  
4 vehicles, going forward. Our Ecotality project has been  
5 going through some revisions. At the latest revision,  
6 we're at 1,000 for a target for residential  
7 installations, 150 to 250 volt installations, still at  
8 1,450 of the public access Level 2, approximately 60 of  
9 the DC, and we have just recently added workplace  
10 charging as the component. This is the only Ecotality  
11 project in the country at this point that presently has  
12 workplace charging added to its mix.

13           Getting the messages across about our EV TOU  
14 rates is another challenge. We have separate metering,  
15 we have whole house, getting the consumer to appreciate  
16 the differences between those two can be a major hurdle  
17 and we put a lot of time and energy - this is some of  
18 the pictorial representation that we are trying to use  
19 to get that message across to the consumer easily,  
20 utilizing our website as the back-up for this, so that  
21 they can get more detail. And we do individual  
22 consultations over the phone for rate analyses.

23           I'm going to skip this, only to say that there  
24 is a broad spectrum of projects that we're working on,  
25 the one that I'm most involved with right now is the

1 last one, the Multi-Unit Dwelling Outreach Program. We  
2 did a presentation yesterday to the Southern California  
3 Section of the California Association of Community  
4 Managers, which are the people that do the property  
5 management for and will be facing the many challenges.  
6 And we heard loud and clear from them yesterday, that  
7 they are feeling a bit overwhelmed with the challenges.  
8 Here is a pictorial representation. You live in one  
9 location, your meter is in another location, your  
10 parking in a separate location, trying to bring those  
11 threads together within a community, as well as the  
12 physical limitations that we have in some of these  
13 facilities. This is an example of a high-rise  
14 condominium and the type of metering configurations that  
15 we're seeing. So, in those instances, dealing with the  
16 legalities that they're dealing with, dealing with the  
17 metering and wiring, and dealing with the cost  
18 allocation to their residents, everything from the non-  
19 communicating infrastructure equipment to something as  
20 advanced as can do individualized billing and  
21 recognition of customer use, and getting them to  
22 appreciate all of the options that they're looking at.

23           We're going to be rolling out next month our  
24 Multi-Unit Dwelling Workshop Program. We will be  
25 providing PEV 101, which is a basic orientation for

1 everyone in the room, and then inviting property  
2 managers, homeowner association presidents, and vehicle  
3 owners to present to others and to give their story as  
4 to how they've worked through these issues, and we have  
5 a checklist that we are providing to multi-unit  
6 dwellings to help them work through these issues. We're  
7 heavily pushing the Goelectricdrive.com resource, which  
8 is a national website developed under EDTA, as well as  
9 our own localized web source.

10           Again, I'm just going to stress that, in  
11 addition to our metering challenges, or notification  
12 challenges, education is where most of the attention is  
13 being placed at this point and getting the word out  
14 through our website, working - we're doing training of  
15 personnel at the dealerships, we're doing training  
16 directly with the contractors and inspectors that are  
17 doing the work in the field, and again, as I mentioned,  
18 the outreach training program. And we have multiple  
19 ways for them to communicate with us and to send us  
20 their questions and to monitor what we're doing going  
21 forward. And thank you. I appreciate it.

22           VICE CHAIR BOYD: Thank you.

23           MR. WENG-GUTIERREZ: Thank you, Joel. Next,  
24 we'll have Russell Vare speaking.

25           MR. VARE: Hi, good morning. I'm Russell Vare

1 with Nissan North America and I have a couple slides  
2 that you can feel free to scroll through for me.

3 I wanted to give the automaker perspective on  
4 infrastructures, and thanks for the opportunity to  
5 speak. If you go to the next slide, that's really just  
6 for reference, it is product details on the Leaf that I  
7 don't need to go over. So, if you go to the next slide,  
8 to give you an update on our launch, we have an  
9 increasing amount of interest in the Leaf, more hand  
10 raisers are registering with the website. Out of our  
11 20,000 initial reservations, we started delivering in  
12 seven states, including California, and have had over  
13 1,000 deliveries so far within North America, and we  
14 reopened reservations for those seven states May 1<sup>st</sup>, so  
15 we're going to see that 20,000 number increase shortly,  
16 so glad to see more cars getting on the road. And out  
17 of that early number of drivers, we have some early data  
18 if you go to the next slide, I kind of take this with a  
19 grain of salt because it's only a few hundred drivers  
20 over a short period, but we are kind of basically seeing  
21 the electric vehicle drivers are doing as expected,  
22 short trips, at home, recharging at home, seven mile  
23 average trip length, most people are charging Level 2 at  
24 home, and the average charge time is two hours and 11  
25 minutes so it's pretty much what we expected, and we

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1 expect most charging to be that kind of bottom part of  
2 the pyramid that we talked about, where it's at home,  
3 and it's at night, and it's off-peak, and we're starting  
4 to see a glimpse of that's what it's going to be. You  
5 know, I would wait to see more data from EV Project and  
6 from the other studies that are going on to have a more  
7 robust look at it, but we are getting a lot of customer  
8 inquiries on public charging - where is it going to be,  
9 how much, how do I have access to it. So, if you go to  
10 the next slide, what we tried to show our customers is  
11 that this is what we have visibility to; we see kind of  
12 11,000 to 12,000 Level 2 and DC fast charging stations  
13 going in around the country so far. You know, we base  
14 this on Level 2 or DC fast charge, publicly accessible,  
15 and J1772 plugs. So it's looking really really good for  
16 California in terms of the number of public charging - I  
17 think 4,000 to 5,000 is kind of what we see in the major  
18 metro areas, which is really good for, I think, building  
19 the market since there is customer demand and customer  
20 interest in having public charging.

21           You know, there are a lot of questions that  
22 focus on the number of stations and, you know, making  
23 sure they're fully utilized, and what time they're used,  
24 but if you go to the next slide, I think what we need to  
25 focus on is whether it's customer-friendly. And, in

1 terms of volume, what we're looking at, if you look at  
2 Tom Turrentine's slide from earlier, the volume for  
3 California is still going to be in the tens of thousands  
4 for the next few years, which is not necessarily going  
5 to be kind of a huge impact on the Grid in terms of  
6 they're charging during the day, and having a public and  
7 workplace charging that the customer uses, likes, wants,  
8 is really going to help build this market. So, you  
9 know, I think what we want to do is make sure we build  
10 the market for electric vehicles where all these  
11 questions about infrastructure become moot if there's  
12 not enough cars on the road to use them. So, if we do  
13 have a public infrastructure that's well-used, that will  
14 probably help work in to these other challenges that we  
15 have with multi-family dwellings and garage-free homes,  
16 that they have confidence they can use public charging  
17 or use workplace charging that has well-designed  
18 policies around it.

19           And one example I have, there is the EV Go  
20 Network, that's a model in Dallas and it's in Texas with  
21 NRG funding it, and they have the public network of  
22 Level 2 and DC Fast Charging that you pay a monthly  
23 subscription to, so it's just one way to look at it.  
24 And, of course, Ecotality and Coulomb have their models  
25 through looking to make it convenient to the customers.

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1 I think that that should be kind of the most important  
2 question as we look at the early market.

3 And then, of course, as we look at the long term  
4 market, following up on what Richard Lowenthal said  
5 about pre-wiring homes and parking garages, as we look  
6 out kind of 2020, what's going to be the easiest and  
7 cheapest way to expand infrastructure, and it's going to  
8 be if we look at pre-wiring homes for today. But those  
9 are updates from Nissan, thanks.

10 VICE CHAIR BOYD: Thanks to you, Russell.

11 MR. WENG-GUTIERREZ: Thanks, Russell. And then  
12 the last panelist is Dan Bowermaster from PG&E.

13 MR. BOWERMASTER: Good morning. So, I didn't  
14 prepare any slides and, if I did, they would be largely  
15 repetitive, like you've already heard. We definitely  
16 agree with what you heard as far as we need data.  
17 Everyone has an opinion, and everyone has a forecast,  
18 and in PG&E's territory, we project by 2020 there will  
19 be between 220,000 and 850,000, and really, the key  
20 inflection point, which we saw in Tom's slides, was the  
21 2014-2015 timeframe, so one of our challenges is, and  
22 here is the focus, is how do you support the market now  
23 while designing programs and services and policies that  
24 help bridge that gap in between the early adopters and  
25 the mass market. And I guess, you know, some of the

1 things - you heard Joel mention a lot about utility work  
2 that is going on right now, the five big utilities in  
3 California, the three IOUs plus SMUD and LADWP are  
4 working quite closely to align the customer experience  
5 as closely as possible. Now, granted, everyone's  
6 reality is slightly different and we all work with the  
7 car companies and the service providers, so every flavor  
8 is quite a bit different, but the big thing that the  
9 utilities have control over is rates. And one bit of  
10 data that hasn't been brought up yet is the second  
11 meter. It was mentioned how expensive to install the  
12 second meter can be, and that can range from \$500.00 all  
13 the way up to - we've seen installation costs in the  
14 \$12,000 range for a second meter. And, so far, the data  
15 size is still statistically insignificant, but  
16 historically, in the mid '90s, we had roughly eight  
17 percent of our customers, electric vehicle customers who  
18 chose the electric vehicle rate, choose the second  
19 meter. Right now, we're seeing it's about 20-25  
20 percent, which isn't surprising if you think about the  
21 profile of the early adopter also having solar, it makes  
22 a lot of sense to keep your solar rate on your house and  
23 then have the electric vehicle rate on that second  
24 meter. But it's important, and something Joel and other  
25 people have mentioned, education. How do we educate

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1 customers up front so they know what, first of all,  
2 their options are as far as electric vehicle rates and  
3 choose whichever one fits their profile. And, secondly,  
4 if they do choose a second meter, what might the range  
5 of costs be? Because we'd hate to have a bad customer  
6 experience, I think, and all of us around the table can  
7 agree that, where a customer almost blindly chooses to  
8 put in a second meter, only to get half-way down the  
9 path and find out it's thousands of dollars to put in a  
10 second meter.

11           So, I guess, to close, I would rather keep this  
12 short so we can open up to questions because I think  
13 that's the most beneficial. So, we are focusing on the  
14 customer, working closely with all the stakeholders, and  
15 so far we really see that it depends on the use case,  
16 you know, San Francisco, as Tom mentioned, is quite  
17 different than, say, a Stockton or a Berlin, for that -  
18 well, not Berlin - but Stockton or Sacramento. So the  
19 solution there might be different and there might be  
20 other solutions in conjunction with public charging or  
21 workplace charging, maybe car sharing will play a bigger  
22 role and maybe there's a way there to support the monies  
23 in that direction. I think we collectively need to  
24 think creatively. I mean, every MUD is different and  
25 every customer is different, and it's really important,

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1 I think, that we figure out solutions and that we don't  
2 generalize one or the other. Granted, a lot of  
3 customers who live in a nice three-car garage house can  
4 charge off-peak overnight at home, which is what we  
5 want, or even at work in the morning before, say, 1:00  
6 or 2:00. But the customer who lives in a high-rise in  
7 San Diego or San Francisco is going to have a very  
8 different need. Thank you.

9 VICE CHAIR BOYD: Thank you.

10 MR. WENG-GUTIERREZ: Thank you. So if there are  
11 any questions for any of the panelists or from -

12 VICE CHAIR BOYD: I have no questions. Are you  
13 entertaining questions from folks in the audience?

14 MR. WENG-GUTIERREZ: Sure, yeah, anyone.

15 VICE CHAIR BOYD: This is a workshop, not a  
16 hearing.

17 MR. WENG-GUTIERREZ: Okay, it looks like - do  
18 you have a question? Go ahead and come up to the podium  
19 and identify yourself.

20 MR. MACCURDY: My name is Dwight MacCurdy. I  
21 work with SMUD in the EV Department. I'm curious about  
22 the availability of the data that will flow under the  
23 Federal Grants, when it will become available to all of  
24 us, when we'll be able to utilize it, and from the car  
25 companies, not only from the EVSP suppliers, but the car

1 companies.

2 MR. LOWENTHAL: I can answer that for Coulomb.  
3 We are already sending data to the Idaho National Lab,  
4 and we would be happy to share that data with you, too.  
5 It is available, so if you just contact us, we can get  
6 that data to you. For Idaho National Labs, we are  
7 tracking for everybody that charges where they charge,  
8 how much they charge, and when they charge, so we're  
9 happy to share that - well, the taxpayers are paying for  
10 it, so we're happy to share it with anybody that wants  
11 it.

12 MR. HEITMANN: Yeah, we have - the project has  
13 obligations for reporting quarterly, and we've worked  
14 through the template, we've shared that with all of our  
15 participating partner utilities in the regions under the  
16 EV project, and we've also developed a customized per  
17 utility variant of that report, so once that data is  
18 collected and put together, it's going to flow out in  
19 these vetted report formats. I have an example here, I  
20 didn't put it up on the slide, but if you'd like, come  
21 and look at it, or we could put it in as a, you know,  
22 formal exhibit. As I mentioned, it's pretty detailed,  
23 it'll look at Volt vs. Leaf use and in different  
24 contexts of public vs. overnight charging, average  
25 ranges, those type of things. But it's very important

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1 that we keep the privacy of the individual users intact,  
2 so the data really, by design, was done in an aggregate  
3 form, but the value of it is there, you know, to see  
4 those type of trends.

5 MR. VARE: And Nissan data will be available  
6 through the Quarterly Annual Reports.

7 MR. HEITMANN: Yeah, one aspect of that, too, I  
8 think, we've been working again with - the utilities  
9 have a very vested interest, I guess, in getting heads  
10 up on where these cars are coming and I know Nissan and  
11 some of the other OEM's have been working with the  
12 utilities and we have, too, to where we can give people  
13 heads up so that they can do some planning,  
14 infrastructure impact planning, because it is a very  
15 real possibility that you could get clusters of several  
16 vehicles in one place and having a heads up on that is  
17 important for utilities.

18 MR. WENG-GUTIERREZ: I guess, to follow-up on  
19 that item, one of the questions that I jotted down was,  
20 if you could speak to the collaborative efforts that are  
21 occurring and what type of collaborative activities do  
22 you have between your different like OEM, utilities,  
23 local agencies? I mean, is it being overseen by certain  
24 agencies? Is the PVEC Collaborative pivotal to that?  
25 Are there other agencies or other mechanisms for

1 communicating these things?

2 MR. POINTON: I think if I were to cite one  
3 particular forum that, for us, has been most efficient,  
4 most supportive, for gathering data, it has been through  
5 the EPRI Infrastructure Working Council, which actually  
6 brings together the automakers, the EVSPs, the  
7 utilities, as well as the supply chain providers. And  
8 it gives us an early indication of where trends are  
9 going. We're going to be seeing these vehicles coming  
10 to market. They're already here, they're at 3.3  
11 kilowatt load on it. We're going to see vehicles going  
12 to 6.6 by the end of this year and there's a disturbing  
13 trend among automakers to discuss going to 19.2 for  
14 residential, which is not a sustainable situation for  
15 utilities. They're looking at this for both the upper  
16 and AC Level 2's, as well as DC Level 1, they're  
17 proposing three levels for DC charging, as well. So  
18 these are trends that we need to monitor early, we need  
19 to offer feedback on, and from our point of view, the  
20 EPRI Infrastructure Working Council, working with SAE on  
21 Standards setting, has been the forum where we get the  
22 most bang for the buck.

23 MR. VARE: I would say the PEV Collaborative -  
24 California PEV Collaborative is a good place for a lot  
25 of this, working together on issues, and there's even

1 several topics that are very specific like the NREL, GOE  
2 EVSE database, looking at infrastructure mapping, and so  
3 there is depending on the topic, there's different  
4 groups working together.

5 And it looks like we have another question.

6 MR. HEITMANN: One last point. I guess part of  
7 our EV project method, deploying in those 18 cities, we  
8 start with what we call a microclimate assessment and it  
9 really is meant to have a framework for people to come  
10 around and collaborate on, and the first benefit of all  
11 that is building those stakeholder alignment, so  
12 utilities are key players in that, as well as Council of  
13 Governments, and other folks that are centered around  
14 that region. And that's a very important first step  
15 just to get everybody literally on the same page, not  
16 that it's not without contention, but it definitely gets  
17 people moving forward towards that first important step  
18 of agreeing, "Yeah, here's where we want to build the  
19 infrastructure."

20 MR. WENG-GUTIERREZ: Great. It looks like we  
21 have a question.

22 MS. GREY: Gina Grey with WSPA. I think we have  
23 two electric utilities on the panel if I'm not mistaken,  
24 and we in the auto industry would be interested in any  
25 comments that you have to provide on, first of all,

1 whether or not you are anticipating opting into the Low  
2 Carbon Fuel Standard Program and, if not, I think we  
3 would like to hear why not; and, if you are, any  
4 projections on the volume of those credits and projected  
5 costs of those credits that the oil industry would have  
6 to purchase? Thank you.

7 MR. POINTON: I can only say that it's still  
8 under review. Internally, I don't have a statement to  
9 make relative to that.

10 MR. BOWERMASTER: Yeah, we're still - PG&E is  
11 still evaluating LCFS, as well.

12 MR. WENG-GUTIERREZ: And I think there is an  
13 LCFS working group, which is talking about these issues  
14 and who would be getting the credits, and how it would  
15 be accrued, so it is certainly still part of the - you  
16 know, still being developed right now, but any insights  
17 that you have, I'm sure everybody would like a piece of  
18 the pie, but any insights would be appreciated.

19 MS. GREY: In particular, since the program  
20 began January 1<sup>st</sup> of this year.

21 MR. WENG-GUTIERREZ: Sure, absolutely.

22 MR. HEITMANN: I would use that as maybe an  
23 opportunity to - it's all about people being aware of  
24 their impact, or mitigation of impact on carbon, so one  
25 of the things we've done is really to extend our network

1 to include things like a home energy controller that  
2 allow people to track and access and monitor those  
3 things, so as credits become more sort of tangible or  
4 fungible, right now, it basically measures or present  
5 displaced carbon based on how much you're using your  
6 electric vehicle, but as things like economic credits  
7 get tied to that, it's a perfect place to bring that in  
8 a consolidated way, so people understand what the whole  
9 picture is of their use of electric vehicles.

10 MR. WENG-GUTIERREZ: Okay, and then I think -  
11 were there any other questions from anyone? All right,  
12 then I guess, with that, we'll go ahead and move on to  
13 the next set of presenters. Thank you very much.

14 VICE CHAIR BOYD: Thank you, Panelists.

15 MR. WENG-GUTIERREZ: So, next we have Steve  
16 Eckhardt from Linde. It looks like he hasn't called in,  
17 so can we go with Ed Heydorn from Air Products?

18 MR. HEYDORN: Thank you. Good morning. I'm Ed  
19 Heydorn from Air Products. Thank you, Commissioner Boyd  
20 and to staff for the invitation to speak today about  
21 questions related to hydrogen infrastructure, the needs,  
22 and the impact on the report that will be generated by  
23 staff in the fall. So, I'll just give a brief overview  
24 talking about the supply chain for hydrogen because  
25 that's going to influence the needs of the stations and

1 the requirements for infrastructure, going forward,  
2 through production and distribution and up to the point  
3 of dispensing. That will get into station deployment  
4 strategies as to how you can best manage infrastructure  
5 during this roll-out of fuel cell vehicles. Some of the  
6 automakers have shared some vehicle information in  
7 response to questions from staff that I'll provide some  
8 information on, and then talk about other issues that  
9 were raised in the questionnaire that we were asked  
10 dealing with quality and Codes and Standards.

11 This is a slide I've used in a number of  
12 presentations to talk about the variety of pathways for  
13 production of hydrogen, either central production with  
14 distribution via pipeline, if you produce liquid  
15 hydrogen, that mode of distribution, you can also  
16 dispense compressed gas for those needs, and even down  
17 to selling requirements for very small users. And  
18 there's also distributive production, where the  
19 hydrogen is produced at the point of use from a variety  
20 of feedstocks. It's one of the beauties of hydrogen and  
21 one of the challenges is that you can make it from a  
22 variety of pathways, and it's really managing the supply  
23 chain that is the key. So, this is another slide  
24 talking about different modes of supply and how they  
25 kind of fit in terms of the overall economics. And it

1 ties into a variety of factors, including distribution  
2 distances and electricity and diesel cost, as well as  
3 volumes.

4           So, hydrogen really is a volume business and low  
5 cost central production can meet requirements today for  
6 transportation. We supply hydrogen into the refining  
7 industry at large volumes, and that is incorporated into  
8 the price of transportation fuels. There was an NREL  
9 study recently that showed hydrogen cost of production  
10 is \$1.33 per kilogram at large volumes, so that's really  
11 just the front end of the supply chain, but it does show  
12 that there is a pathway to produce hydrogen at very low  
13 cost today.

14           Yesterday, we participated in the opening of a  
15 hydrogen fueling station in Torrance that's directly fed  
16 from an Air Products industrial pipeline that serves the  
17 refining industry. That station provides a - what I  
18 look at as more of a future pathway to supply hydrogen  
19 when there are a significantly large number of vehicles,  
20 but today you have to approach things in a different  
21 tact in order to successfully roll out infrastructure.

22           So this is really the current supply chain for  
23 hydrogen associated with vehicle fueling, starting from  
24 the point of production through distribution, storage  
25 on-site, and then preparation for fueling and, finally,

1 dispensing to the car. Now, the key is really to find  
2 an approach to distribute low cost hydrogen from central  
3 production facilities to points of use, and California  
4 is fortunate that there is excess hydrogen capacity from  
5 various suppliers, including Air Products, and so there  
6 are ways to utilize that capacity without at this phase  
7 of infrastructure development to invest in new  
8 production methods, that those can wait until more  
9 vehicles are in place. So that investment doesn't need  
10 to be made today to support vehicle infrastructure.

11           Now, in terms of station considerations, kind of  
12 the easy part of the solution is that we can build  
13 stations now for very large through-puts, for example,  
14 for material handling, or mass transit projects. Those  
15 are projects that are ongoing and that are done - one  
16 example is with liquid hydrogen with liquid compression,  
17 with redundancy for the compression steps and multiple  
18 dispensers to serve the number of users for these sites.

19           But there are issues for going to the large  
20 station today for light-duty vehicles. It extends the  
21 time where the utilization is low; if you have to put in  
22 a very large station, it will take longer time to get  
23 that station up to full utilization and into its best  
24 capital point. Also, footprint. For gasoline stations  
25 where we're seeking to install refueling stations, how

1 many of them are really amenable to these larger  
2 footprint requirements? And is that really needed  
3 today, given the strategies for roll-out of vehicles?  
4 And also, depending on the type of infrastructure you  
5 invest in, you could have those assets potentially  
6 under-utilized by future innovations. The people in the  
7 supply chain for hydrogen are continuing to look at new  
8 ways to produce, distribute, and dispense hydrogen, and  
9 there's also innovations on the vehicle side that  
10 continue to be made. So, it's best not to over-invest,  
11 in my view, in an infrastructure that make it outmoded  
12 over a relatively short period of time.

13           This is a map of stations that were selected by  
14 the Energy Commission under the aforementioned AB 118  
15 Program. It's the beginnings of a network in Southern  
16 California that the idea is to try and build the  
17 stations at the points of use where the automakers are  
18 providing input to the Commission, and to infrastructure  
19 providers, to say these are the best early markets where  
20 vehicles are going to be deployed.

21           The challenge and the opportunity for the fuel  
22 cell vehicle is the fact that they have such extended  
23 range, it's not reasonable to try and have them tethered  
24 to a particular station. So, the strategy that the  
25 automakers are proposing and that we're trying to serve

1 into is the idea of providing a coverage area within the  
2 early markets, is to meet the needs of the consumers, to  
3 be able to drive where they want to, and not be  
4 benchmarked to a particular station. I mean, you could  
5 build one 2,000 kilogram a day station and that could  
6 provide enough capacity to be able to satisfy those  
7 needs of the vehicle market, but, as we all know, we  
8 like to drive different places, different times, and as  
9 I said, be un-tethered.

10           So, as you look at infrastructure, if you look  
11 at the infrastructure investment, there are different  
12 ways you could approach it in terms of the number of  
13 stations, depending on the amount of investment that's  
14 needed for those. And so, in order to try and meet  
15 these coverage needs, that the automakers and their  
16 customers are seeking, we're looking to try and serve  
17 those markets utilizing modeling tools. There's a  
18 recent development from the folks at the University of  
19 California Irvine who is, I believe, under contract with  
20 the Energy Commission that looks at siting methodologies  
21 for fueling stations, not just for hydrogen, but for  
22 other fuels. And so, using these type of modeling tools  
23 combined with the market data from the auto makers, can  
24 help target infrastructure deployment so that  
25 investments are made at the right point and to the right

1 level where it's not over-investing. So this would help  
2 support the development of the clusters, which  
3 automakers have talked about for a number of years as a  
4 key approach to start the market, and then also  
5 considering destination stations and, again, you know,  
6 the question is do you want to put a \$3 million  
7 investment at a station that's going to be lightly used  
8 for a long enough period of time until it becomes a  
9 cluster in the future.

10           So the solution that we are developing and  
11 installing at the stations under the initial AB 118  
12 award is looking to drive station costs down to \$1  
13 million or less, and what it does is it accomplishes  
14 that by reducing the amount of infrastructure needed at  
15 the forecourt and centralizing that at the point of  
16 production instead of the point of use. It allows for  
17 ease of expansion and it also allows the market to  
18 determine when a station is expanded, so it's not,  
19 again, over-investing today until the market is more  
20 fully developed.

21           Now, we have submitted information to the docket  
22 for the 2011-2012 AB 118 Investment Plan, it talks about  
23 hydrogen pricing for this type of station model, and we  
24 show that the pricing is attractive for transportation  
25 and these are stations, you know, 300-500 kilograms a

1 day, so they are not the super large stations that were  
2 thought of in the past. One of the questions that we  
3 were asked for is about tax structure, but with this  
4 type of fuel pricing, \$7.00 a kilogram untaxed, you  
5 could certainly operate in the tax structure as you do  
6 with other transportation fuels.

7           One of the opportunities and challenges that  
8 we're looking at with the various stakeholders is how  
9 you deal with fixed operating costs of the stations  
10 during the time before vehicles come out in large enough  
11 numbers to fully utilize the station, things like  
12 insurance and property tax that a station owner will  
13 have to incur, even if he doesn't sell one drop of  
14 hydrogen.

15           These are numbers that have been developed  
16 through surveys from the California Fuel Cell  
17 Partnership, which I know the Commission is very  
18 familiar with. It talks about how the transition will  
19 roll from hundreds to thousands in the 2015 to 2017  
20 timeframe, tens of thousands of vehicles. And in the  
21 bottom left there are some operating results to date  
22 from the vehicle and bus programs that have been  
23 undertaken.

24           With regards to the pricing, this is a chart  
25 that Toyota has provided and I think they shared in

1 other venues, that talk about cost of vehicles as a  
2 function of driving range, looking at fuel cell vehicles  
3 being fairly well developed in their minds, in terms of  
4 cost structure, with the increase in cost really just  
5 based on the amount of additional storage that's needed  
6 on board the vehicle to get the additional range.

7           So, fuel cell systems and mass production in  
8 many of the OEM's minds is an attractive pathway to meet  
9 vehicle owner needs for range and convenience of  
10 fueling. And we were asked to talk about hydrogen  
11 quality and issues that we see going forward. As I  
12 mentioned before, hydrogen could be made from a variety  
13 of sources, both from dedicated production plants, and  
14 also byproducts from other chemical production  
15 facilities. There is a Standards evolution going on for  
16 hydrogen for vehicle fueling, there are certain  
17 components that are more difficult to separate from  
18 purification standpoint. These type of specifications  
19 could disqualify certain feedstocks from being amenable  
20 for fuel cell application, so that's something that  
21 we're working through in terms of the development of the  
22 standards. Some of them are still - some of these  
23 standards that are being proposed, there have to be  
24 measurement techniques associated with those, they're  
25 not altogether proven yet, so in that world, there are a

1 series of round robin testing that has been proposed to  
2 be able to validate the standards, so that we can, as a  
3 supplier, in order to meet quality control requirements,  
4 we have to be able to get the performance of the  
5 standard, the degree of accuracy, and then put in our  
6 quality control measures to be able to understand where  
7 our production point needs to be to meet those  
8 requirements.

9           Now, in terms of any of these test methods, it  
10 always ends up adding costs for analyzers that would be  
11 installed and just operation and maintenance, just  
12 validating analyzers. I mentioned about confirmation of  
13 the test methods and one of the things to consider about  
14 analysis within the supply chain is it is obviously  
15 easier to do at a large central facility than in a  
16 distributed production method, that is one of the hidden  
17 costs of hydrogen from a distributed method vs.  
18 centralized, because now you're going to have to have  
19 distributed analytical capabilities at all the points of  
20 use.

21           And today, hydrogen is already made at ultra  
22 high purity, so there are costs just associated with  
23 recoveries, I mean, we provide hydrogen to the  
24 electronics industry of very high purity, and the  
25 question is how far do the standards need to go from the

1 vehicle side in order to make the overall proposition  
2 work. It's a question of balancing out the needs on the  
3 fuel cell vs. the availability to produce and validate  
4 the hydrogen that is being produced.

5           It's also asked about other Codes and Standards  
6 topics, Air Products participates in organizations that  
7 develop Codes and Standards; one of the things we see,  
8 not just in California, but in other parts of the  
9 country is, depending on the local rules, the  
10 authorities having jurisdictions have different  
11 interpretations of the Codes, and that leads a lot of  
12 times to different results at different locations for  
13 the same hardware, so that becomes a challenge for the  
14 speed to be able to roll infrastructure out. And what  
15 we're trying to do with our system within the eight  
16 station deployment under the AB 118 program is to  
17 standardize that kit, essentially, so that we can roll  
18 out the same equipment at all the sites so that there is  
19 a certainty from a permitting standpoint, and obviously  
20 from an operation and maintenance view, as well.

21           With the smaller stations, because there are  
22 more options to do, waste to produce or distribute and  
23 provide the hydrogen, you end up with hundreds or even  
24 thousands of configurations. So the fact that the  
25 stations are starting to get larger, it starts narrowing

1 down the options for the hydrogen that's going into the  
2 forecourt, which will hopefully simplify the permitting  
3 aspects of it, and as I mentioned, stations getting  
4 large or the options will be less.

5 One other topic that I didn't put on the slide,  
6 there was a question on hydrogen metering and the work  
7 that the CEC is sponsoring with the Department of Food  
8 and Agriculture, we continue to support those efforts to  
9 look for a solution to be able to achieve unit pricing  
10 at the point of sale for hydrogen. We see it as a  
11 solvable problem, it's like a lot of the components  
12 within the hydrogen industry, volume will help take care  
13 of a lot of it to incent the makers of instrumentation  
14 to be able to come up with a solution, to be able to  
15 provide accurate measurement from very low pressures up  
16 to the 700 bar levels that the vehicles currently  
17 require, but we continue to support those efforts and  
18 the efforts within the state to try and promote those  
19 solutions. So, again, I thank you for your time and for  
20 the invitation, and I don't know if I can take questions  
21 now, or if that's later in the program?

22 MR. ECKHARDT: Good morning. Can you hear me?

23 VICE CHAIR BOYD: We can, thank you.

24 MR. ECKHARDT: All right, good morning. Well,  
25 my name is Steve Eckhardt, I lead Linde's Business

1 Development activities for Hydrogen Fueling and we'd  
2 just like to thank the Energy Commission for inviting  
3 Linde to present here today.

4 Linde is a \$15 billion multi-national gasses and  
5 engineering company and we supply hydrogen, oxygen,  
6 nitrogen, and many other gasses to a multitude of  
7 industries. Can we move on to the next slide?

8 By the end of 2012, we'll have supplied no fewer  
9 than six hydrogen fueling stations in California. Of  
10 these, we are currently building three fueling stations  
11 for AC Transit. Two of these stations are for their  
12 fleet of fuel cell busses, and one is for light-duty  
13 fueling of vehicles. Both the CEC and the ARB awarded  
14 funding to AC Transit for these stations and that  
15 leveraged a significant amount of funding that was  
16 provided by the Federal Government, as well, for those  
17 installations. In addition to that, Linde was recently  
18 awarded for three car fueling stations from the Energy  
19 Commission, with recently here in 2010, and those will  
20 be located at San Francisco Airport, West Sacramento,  
21 and Laguna Niguel. We expect all those will be  
22 operational next year, and these will represent the  
23 highest throughput hydrogen fueling stations in the  
24 country and they're fully compliant with all industry  
25 specs for fast fueling.

1           If you look at the bottom of this sheet, fuel  
2 cell vehicles offer California a vehicle with zero  
3 tailpipe emissions, vehicles that are running on  
4 domestically produced fuel, vehicles that reduce carbon  
5 emissions by 40 percent or more, depending on the source  
6 of the fuel, and based on the public announcements by  
7 the car companies, these cars will be priced  
8 competitively starting in 2015, with conventional hybrid  
9 vehicles. We believe these vehicles are a critical  
10 component of the State's plan to meet the goal of 80  
11 percent carbon reduction by 2050. Next slide.

12           I think it's important for a few minutes just to  
13 talk about what is happening around the world with fuel  
14 cell vehicles and hydrogen fueling, so if you look at  
15 the top slide, in Germany, a consortium of industry and  
16 government, which is called H2 Mobility, has defined  
17 detailed plans for the deployment of about a thousand  
18 stations in Germany by 2017. In Japan and in Korea,  
19 there have been recent announcements, as well, for the  
20 deployment of hundreds of stations.

21           We have worked with the car companies for many  
22 years in supplying hydrogen, supplying hydrogen fueling  
23 stations for these vehicles, and then developing the  
24 industry standards for hydrogen fueling. And through  
25 our partnership with the car companies, we've learned

1 much about the vehicles and the commitment of the  
2 industry to deploy them. We believe these cars will be  
3 deployed and, hence, we are investing significant  
4 dollars into research, development, and deployment of  
5 hydrogen fueling technologies around the world.

6 Right now, we believe the only unanswered  
7 question is where the vehicles will be deployed. Linde  
8 strongly believes that California is one of the key  
9 places for fuel cell vehicles to be initially deployed,  
10 and if industry and government work closely together in  
11 rolling out the infrastructure required, we are  
12 confident California will track many thousands of fuel  
13 cell vehicles. But it's important to remember, this is  
14 indeed a competition and it is important we recognize  
15 that we must develop an infrastructure that can properly  
16 fuel these vehicles and offer a superior value  
17 proposition for the drivers. While these steps won't be  
18 easy, we think they're definitely achievable, and will  
19 ensure fuel cell vehicles are soon on California roads  
20 and highways as an important step in the emissions  
21 reductions plan.

22 Now, in California, I think we're off to a good  
23 start. With CARB funding, about \$14 million in 2008 and  
24 2009, for seven car stations, and then the recent Energy  
25 Commission funding of over \$15 million for 11 car

1 stations in 2010. The funding for these stations will  
2 allow industry to deploy public fueling stations that we  
3 hope will exceed drivers' expectations.

4 As I indicated before, Linde is supplying four  
5 of these stations for auto fueling in Northern and  
6 Southern California, and we appreciate that the Energy  
7 Commission recognized our technology, our business  
8 model, and our partners for the award of these grants  
9 for the stations.

10 Linde will be supplying hydrogen to these sites  
11 mainly through delivery of liquid hydrogen, but also  
12 from an electrolyzer supplied by Proton Energy Systems.  
13 In addition, Linde can supply hydrogen from sources  
14 located in Chicago, as far away as Quebec, even, and I  
15 think it's important to note that our hydrogen plant in  
16 Quebec is supplied by a Sodium Chloride plant, which  
17 actually uses water as a feedstock. We then take that  
18 byproduct, hydrogen, and use green hydroelectric power  
19 and produce what is a 97 percent renewable hydrogen.  
20 And I think this goes to show that it is possible to  
21 produce renewable green hydrogen and it can be done  
22 anywhere or in many places in North America.

23 In addition, hydrogen can be produced by  
24 electrolysis of water and the main way right now is the  
25 reformation of natural gas or renewable biogas. Most of

1 the hydrogen available today, as I said, is produced  
2 from the reformation of natural gas and this process can  
3 be done both at a central hydrogen production facility,  
4 or on-site if the demand is sufficiently large, and I'll  
5 talk a little bit more about that in a few minutes.

6 Next slide.

7           So liquid and compressed delivered hydrogen to  
8 the site is likely going to be the predominant supply  
9 for the next several years due to the economics and due  
10 to the demand levels at each station site. It's  
11 important that we appreciate the cost of delivered  
12 hydrogen is competitive with gasoline today, based on  
13 vehicle miles driven per unit of energy, and it offers  
14 really what I think is an outstanding value proposition:  
15 switch from an imported fuel which produces emissions at  
16 the tailpipe, to a fuel that is domestically produced,  
17 can be renewable, and emits only water vapor at the  
18 tailpipe, and is about the same cost as gasoline.

19           Now, in the future, when hydrogen demand by fuel  
20 cell vehicles outstrips the current supply, new  
21 centrally located hydrogen production facilities will be  
22 built, which will be larger than the current plants.  
23 These larger production plants will bring economies of  
24 scale and improved energy efficiency. And when hydrogen  
25 demand in a single fueling station is on the order of

1 200 fuelings per day, on-site production of hydrogen  
2 will be a viable option. The cost of hydrogen fuel  
3 produced on-site can produce cost savings compared to  
4 delivered hydrogen, and another benefit is that this  
5 option does not rely on frequent deliveries of hydrogen  
6 to the site.

7           So, in summary, it is our view that hydrogen can  
8 be produced cost competitively compared with  
9 conventional gasoline, and it offers a superior value  
10 proposition for fuel cell drivers in the State of  
11 California. As I've noted here, it eliminates tailpipe  
12 emissions, provides a significant reduction in well to  
13 wheel carbon emissions, it is a domestically produced  
14 fuel, which reduces dependence on foreign oil, and it  
15 can be produced from renewable sources. Next slide,  
16 please.

17           So, with respect to hydrogen fueling  
18 infrastructure, I'll spend a few minutes talking about  
19 this, we built over 70 hydrogen fueling stations around  
20 the world and have significant experience with a number  
21 of different technologies. We can compress hydrogen in  
22 a 900 bar, which is well over 10,000 PSI, and that's  
23 sufficient, then, for fueling a 700 bar vehicle quickly  
24 and, back to back, offering the driver with an  
25 experience similar to that of conventional fueling.

1           Linde believes the number of stations required  
2 to meet the needs of fuel cell drivers should consider a  
3 number of factors, which are listed here on the bottom  
4 slide, and those include the number of fueling points by  
5 geographic area. Now, this will ensure that we have  
6 good local coverage, or good neighborhood coverage where  
7 somebody lives. Second, considering hourly peak fueling  
8 capability to ensure continuous back to back fueling  
9 capability during rush hours. During rush hour is when  
10 many people are going to fuel and we need to make sure  
11 that the capacity is available for people to show up at  
12 the sites during rush hour and not have to wait for a  
13 dispenser. And finally, the daily fueling capacity is  
14 important to understand long term what the capability of  
15 a station would be. It should be noted the industry has  
16 indicated on the order of 40 stations should be  
17 operational by 2015 to ensure drivers' needs are met.  
18 Next slide, please.

19           The other item we think is important to comment  
20 on is that we need to show stakeholders, government, car  
21 makers, oil companies, and investors, that the  
22 technology exists to fuel many cars at a site, at the  
23 lowest possible cost. These types of stations are the  
24 ones that will attract the investors with the lowest  
25 cost per kilogram dispensed and will drive the industry

1 to expand on its own in the future without government  
2 funding. In addition, these stations will be necessary  
3 to fuel the large numbers of vehicles scheduled to be on  
4 the road starting in 2015, when car companies begin to  
5 sell these cars to consumers in the thousands. And it  
6 is incumbent on the fueling infrastructure suppliers to  
7 prove this can be done.

8           On the bottom slide, you can see there kind of a  
9 summary or an example of the types of stations that can  
10 be deployed. If we consider that there could be about  
11 10,000 vehicles on the road in 2015, which would be on  
12 the way to what the car companies have projected, 53,000  
13 in 2017, the hydrogen fueling infrastructure must be  
14 capable of dispensing about 10,000 kilograms a day of  
15 hydrogen, assuming 1 kilogram a day per car of  
16 consumption. The proposed combination is 150 kilogram  
17 per day stations and 750 kilogram per day stations, and  
18 this allows all these drivers with the ability to fuel  
19 at any one of these 40 stations. Now, the assumptions  
20 on an example like this certainly can be tweaked, and  
21 they should be debated. The mix of stations can be  
22 changed, the size of the stations may be different, and  
23 capacity utilization of the stations may be higher or  
24 lower, but the end result, Linde believes, is quite  
25 clear: by 2015, the industry will require on the order

1 of 40 stations and a healthy proportion of these  
2 stations must be high throughput stations. As I noted  
3 before, the stakeholders will need to be convinced the  
4 infrastructure is capable of fueling cars. A comment on  
5 that is in the next few slides from three different  
6 perspectives, practicality, technology, and economics.  
7 Simply speaking, can hydrogen fueling be successfully  
8 integrated into gasoline station forecourts? Next  
9 slide, please.

10 First is practicality. As the industry matures,  
11 hydrogen fueling stations must be able to at least  
12 approach the levels of throughput of gasoline stations.  
13 The higher volume gasoline stations can fuel anywhere  
14 from 200,000 to 400,000 gallons a month, and this  
15 translates into roughly 500 to 1,200 fuelings per day.  
16 If you look at a 750 to maybe 1,000 kilogram per day  
17 hydrogen station, that would perform on the order of  
18 200-300 fuelings per day. This hydrogen throughput is  
19 on the same order of magnitude as a gasoline station,  
20 and we believe this is what is necessary to show the  
21 stakeholders that, yes, indeed, hydrogen stations with  
22 high throughputs have been real world tested and can  
23 operate at high throughputs.

24 The second item is on technology, the bottom  
25 slide here. Fueling five cars a day can be done with

1 conventional technology, but fueling 250 a day will  
2 require new technology and undoubtedly the industry is  
3 developing that technology today. Linde has two leading  
4 edge technologies, one is ionic compression, which  
5 compresses the steel cylinder in the compressor with  
6 ionic fluid and that yields a significant increase in  
7 throughput and improved efficiency. We also have  
8 cryogenic liquid pumps, which can deliver even higher  
9 volumes of hydrogen with significant productions in  
10 energy consumption. And I think it is important to  
11 understand these are not ideas, these are not on the  
12 drawing board, these are not in the lab. Linde will  
13 deploy both of these technologies in real world auto  
14 fueling applications in Germany this year, so we can  
15 confidently say that the technology is available to do  
16 this type of fueling.

17 Another item I would also like to mention is  
18 that we're working on resolving the forecourt space  
19 constraints. As we all know, gasoline stations have  
20 limited space to have both gasoline fueling, as well as  
21 hydrogen fueling, and we need to find ways to not only  
22 bring the size of the equipment down, but find somewhere  
23 else to place that equipment. So we are looking at  
24 building stations with equipment below grade. Our first  
25 installation in Munich, it is already operational, and

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1 it includes the hydrogen tank located below grade, and  
2 we are just in the process of finishing commissioning  
3 our second below grade installation in Berlin, and that  
4 will include both liquid hydrogen and hydrogen  
5 compression underground, which absolutely minimizes the  
6 amount of space you're going to take on the forecourt.  
7 The example of that, and our rendition of that, is shown  
8 in the upper right-hand corner of that bottom slide.  
9 And the lessons that we get out of these installations  
10 will certainly be leveraged as we approach the day in  
11 California when this type of installation is warranted.  
12 Next slide.

13           The next item is economics. The capital cost of  
14 Linde's high throughput fueling stations are a small  
15 premium over existing lower throughput stations, and  
16 when one considers what the cost is per kilogram  
17 dispensed into the vehicle, the cost is drastically  
18 lower. The station design can be supplied by other  
19 liquid or gaseous hydrogen, and we believe the cost will  
20 be sufficiently low that, when we combine the cost of  
21 hydrogen fuel with the per kilogram cost of the hydrogen  
22 dispensed for the high throughput station, the overall  
23 cost of the hydrogen dispensed into the vehicle will be  
24 comparable to that of gasoline today.

25           And we don't believe it is wise to wait to

1 deploy these high capacity stations in 2015 or later  
2 when significant numbers of cars are already on the  
3 road. In 2015, we hope that investors will already see  
4 the value proposition such that they are attracted to  
5 the market, and already investing in it in 2014 and '15.  
6 To do that, we must be operating these stations by 2013,  
7 so we can prove to investors, to the stakeholders, that  
8 it is feasible.

9           This equipment has a long life and since these  
10 stations are very high throughput, we believe they can  
11 be operated well past 2015, and through the rest of the  
12 decade with very little additional investment, other  
13 than an additional dispenser as demand grows. Next  
14 slide, please.

15           Small stations are fine when building an  
16 infrastructure or when you need connector stations, but  
17 we need large stations and we want to serve customers  
18 truly cost efficiently, and at the lowest possible  
19 dispensed cost. This was true for the one pump station  
20 which certainly served its purpose during the last big  
21 infrastructure build-up, gasoline stations. But now it  
22 is replaced by larger and more economic gas stations.  
23 We will be seeing a similar development in hydrogen and  
24 we should manage that build-up today with the right  
25 balance of small, lower capital stations, and large more

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1 cost-effective stations.

2           On the bottom of this slide, you can see a web  
3 link to a study that was done by a consortium of  
4 European industrial and government organizations. It's  
5 available on that web link and contains a significant  
6 amount of detail on fuel cell vehicles, hydrogen  
7 production, and hydrogen fueling infrastructure, and I  
8 would strongly encourage those who are interested in  
9 further detail about the study to review the  
10 information.

11           Finally, I would like to just comment on a  
12 couple of challenges that we think require close  
13 collaboration between government and industry and, in  
14 fact, some of that collaboration has already happening  
15 and we just want to encourage that it expand and  
16 continue to grow. The first is with respect to local  
17 permitting and planning for alternative fuels.  
18 Hydrogen, like most of the other alternative fuels we're  
19 talking about here today, it's new and hence the public  
20 and public officials have to be very well educated to  
21 ensure unnecessary barriers are not placed in front of  
22 these stations as they're deployed. These type of  
23 barriers are just going to slow down the deployment and  
24 increase the cost of introducing alternative fuels to  
25 California. Already, Linde and the California Fuel Cell

1 Partnership are actively educating the communities where  
2 we will deploy hydrogen stations, but we do think it's  
3 appropriate and important that this effort be expanded  
4 to include more stakeholders and be better coordinated  
5 going into the future to ensure that stations go in on  
6 time and can go in cost-effectively.

7 Another item I'd just like to comment on is  
8 dispenser certification. It is critical that we get to  
9 a point where we can charge for hydrogen on a per  
10 kilogram basis, and that will require certification by  
11 the DMS. The Energy Commission has granted money to DMS  
12 to actually do this, and we would just like to reinforce  
13 the need for all these stations to be certified in a  
14 timely manner, so that all stations can charge for  
15 hydrogen on a per kilogram basis.

16 So just a closing comment. Linde truly believes  
17 a business case exists for hydrogen fueling in the near  
18 future, and we're investing money and resources in  
19 California and around the world because of this. We  
20 appreciate and encourage continued government support  
21 for infrastructure until the day comes when sufficient  
22 vehicles are on the road to load up our stations, and  
23 make this a value proposition that companies both large  
24 and small will want to pursue on their own. Thank you  
25 for your time.

1           VICE CHAIR BOYD: Thank you, Mr. Eckhardt. If  
2 you would stay on the phone, I think now is the time for  
3 any questions from folks in the audience of yourself or  
4 Mr. Heydorn. So are there any questions? Gina?

5           MS. GREY: Gina Grey with WSPA. And I think  
6 most of these questions I have are actually going to be  
7 directed to Linde vs. Air Products, but would appreciate  
8 responses from either company.

9           The first question is, I think I heard you say  
10 that, so far, between ARB and the AB 118 monies at CEC,  
11 that that will be funding 18 hydrogen facilities, but  
12 that you propose that we would need 40 in the state by  
13 2015. Is that correct?

14          MR. ECKHARDT: The 40 is a number that has been  
15 proposed by the car companies in the California Fuel  
16 Cell Partnership.

17          MS. GREY: Okie doke, thank you. And Air  
18 Products mentioned, for a low volume station, I believe  
19 it was, a million dollar, I guess, investment for that.  
20 I was wondering the cost, I wasn't quite sure on your  
21 slides, you mentioned a dollar per kilogram, but what  
22 would be a total cost for a high throughput facility?

23          MR. ECKHARDT: At this point, I couldn't comment  
24 on specific dollar amounts for the higher - say, over  
25 500 kilogram per day station, but we can say that it

1 would be at a small premium to the stations we are  
2 supplying today, which are on the order of 200 kilogram  
3 per day stations.

4 MS. GREY: Small premium, okay, and what - I  
5 guess the dollars that are coming from AB 118, maybe we  
6 could go there for a second, per station, maybe that  
7 would give us some idea of what it's costing right now.  
8 Are those low volume? High volume?

9 MR. ECKHARDT: The stations that Linde is  
10 supplying were noted in our proposals as 240 kilogram  
11 per day stations.

12 MS. GREY: At a cost -

13 MR. ECKHARDT: I can't comment on any of the  
14 other stations.

15 MS. GREY: Okay, and do you have a cost for each  
16 one of those?

17 MR. ECKHARDT: No, I don't have that at this  
18 time.

19 MS. GREY: Okay, I guess, you know, the question  
20 kind of surfaces that we're pretty familiar with the  
21 fact that ARB has the Clean Fuel Outlet Regulation that  
22 went into play in 1990, it has not yet ever been  
23 triggered, it put the oil industry on the hook for  
24 mandatorily putting in renewable or alternative fuel  
25 facilities at retail and, of course, in 1990, our

1 companies actually did have quite a few of those  
2 stations, they were owners, etc., as was pointed out  
3 earlier, currently I think there's only about two  
4 percent of the stations in California that are owned by  
5 the majors, so they are owned by small independent  
6 businessmen. So, a couple of questions here, you  
7 mentioned Germany, Japan, and I think some other  
8 countries that were moving ahead with putting in  
9 hydrogen facilities at retail; who is paying for that?  
10 Is that government, the taxpayer in those countries?  
11 And then, in your estimation for California, granted, we  
12 may have a Clean Fuel Outlet Regulation in place, but  
13 again, the folks who would have to fork over the dollars  
14 to put all these facilities in, even if they're a small  
15 volume million dollar type scenario, probably are not in  
16 the financial situation to actually move forward and do  
17 that, so do you foresee that this would be something  
18 that Linde and Air Products may move forward and do  
19 this, since you are forecasting a business case at this  
20 point for these facilities? Or are you looking for  
21 these additional 22 or so stations that the car  
22 manufacturers sort of indicated are needed by 2015, are  
23 those dollars going to be coming from, say, AB 118 or  
24 other sources?

25 MR. HEYDORN: This is Ed Heydorn. I can answer

1 the question on station investment. In our docket  
2 submission to the 2011-2012 Investment Plan, we provided  
3 specific information on the amount of dollars that would  
4 need to be invested in Southern California. In our  
5 view, what would be sufficient to complete the roll-out  
6 of infrastructure in advance of deployment of vehicles,  
7 after which investment could be done on a more  
8 commercial basis because there would be enough volume of  
9 traffic through the stations to be able to support the  
10 added investment, either for new stations, or for  
11 expansion to existing stations. So, if I can refer you  
12 to the docket, I think that would be the best answer.  
13 We're very supportive of the continued efforts of the  
14 Energy Commission and staff to support hydrogen  
15 infrastructure, so we can make the projected deployment  
16 of vehicles in the 2015 timeframe successful.

17 MR. ECKHARDT: This is Steve Eckhardt. With  
18 respect to Germany, the funding for stations in Germany  
19 is both coming from government and from industry. I am  
20 not aware of how it's being done in Japan and Korea.  
21 With respect to California, you know, we encourage that  
22 we take a similar approach to that in Germany where it  
23 is both a government and industry investment here in the  
24 short term until there are sufficient number of cars  
25 such that industry can justify that investment on their

1 own.

2 MS. GREY: Okay, thank you. And by "industry,"  
3 what industry is that?

4 MR. ECKHARDT: Those that are - anybody who  
5 would want to invest in putting a hydrogen fueling  
6 station in - when someone who wants to invest in a  
7 hydrogen fueling station sees, as Ed had mentioned, sees  
8 the number of cars out there that will justify that  
9 investment, so it could be investors, it could be oil  
10 companies, it could be industrial gas companies, it  
11 could be anybody.

12 MS. GREY: Okay, is Linde one of those industry  
13 partners there?

14 MR. ECKHARDT: Yes.

15 MS. GREY: Okay, thank you.

16 MR. HEYDORN: As is Air products and many of the  
17 other industrial gas companies are participating in that  
18 study, as well - the actual implementation.

19 VICE CHAIR BOYD: Excuse me, any other  
20 questions? All right. Seeing none, thank you, both  
21 gentlemen, for your presentation.

22 MR. ECKHARDT: Thank you.

23 MR. WENG-GUTIERREZ: So I think, with that, we  
24 are going to break for lunch, so we are a few minutes  
25 behind schedule here, but not too bad, so we'll come

1 back - I guess we'll return at about 1:45, so we'll take  
2 a little bit over an hour for lunch.

3 (Recess at 12:42 p.m.)

4 (Reconvene at 1:50 p.m.)

5 MR. WENG-GUTIERREZ: We still have a long  
6 afternoon in front of us and we're about 25 minutes  
7 behind where we thought we would be, so that's not too  
8 bad.

9 But we're going to go ahead and just jump right  
10 into it. The next speaker we have is Matt Horton, from  
11 Propel Biofuels, and he'll be talking on the biofuels in  
12 retail station permitting. So, if you could come up?

13 MR. HORTON: Great, thanks. Good afternoon  
14 everybody, excited to be here.

15 I'm going to walk through some of the real-world  
16 experience that we've installing a bunch of E85  
17 locations here in California over the last couple of  
18 years.

19 VICE CHAIR BOYD: How painful will this be? No.

20 MR. HORTON: I'll show you the scars in a  
21 minute.

22 But I just wanted to start with a couple of  
23 slides about Propel. I know a number of you are not  
24 real familiar with our company. But our mission is to  
25 build a brand around clean fuels and we want to build a

1 leading clean fuel brand. And we're doing that by  
2 building out a large number of retail access points  
3 where customers can become familiar with renewable  
4 fuels. One of those is E85 Ethanol, today.

5 Our model, we've really set up our business to  
6 try to be a good partner for the existing fueling  
7 infrastructure. We work with individual station owners  
8 to bring new fuels equipment to those sites, the  
9 equipment required to dispense -- store and dispense  
10 renewable fuels.

11 We partner with the existing site owners, so we  
12 offer all of the, you know, marketing, customer outreach  
13 and a lot of the activities, and services that we think  
14 are really important in early stage markets, like this,  
15 to help customers get comfortable using renewable fuels  
16 for the first time.

17 And for us, this approach provides a number of  
18 benefits. It helps us keep our operating capital costs  
19 lower, it helps our stations become profitable, lower  
20 volumes. And we're really focusing on building the  
21 scale of the network so that we're in convenient  
22 locations for the customers, and providing them with  
23 some brand consistency to help drive some loyalty and  
24 confidence in the fuels that they're purchasing.

25 Today, Propel has the largest number of E85

1 locations in the State. We've got 18 that we've opened  
2 today, 23 are in permitting right now, we're working  
3 through that process and hope to opening a number of  
4 those soon. We're pleased to be -- have a grand opening  
5 on our Redwood City site next week. And anyone who  
6 would like to is invited next Tuesday, in Redwood City.

7           We've got a number of other contracts that are  
8 signed and ready to go into permitting right now. And  
9 our plan is to bring about a hundred fifty of these  
10 stations to the State of California by 2015.

11           Here are a couple images of the work we've done  
12 so far, with some of the station partners that we've  
13 worked with. We have two installation types, typically.  
14 There's one that we offer that is a stand-alone option,  
15 where we can -- we essentially build our own small  
16 canopy on the site of our station partner.

17           And in other sites we've worked with the station  
18 owner to actually install a dispenser, a Propel  
19 dispenser under an existing canopy. So, there are a few  
20 images, a couple of these are here in Sacramento, and  
21 one of those is a Southern California site.

22           We are, just to mention, we're in Sacramento,  
23 the San Francisco Bay Area, and L.A., and San Diego at  
24 present.

25           We think there is tremendous upside in

1 California for renewable fuels, in particular for E85.  
2 Nationally, you know, the numbers say that there are  
3 about 1,500 cars per gas station. In California we have  
4 7,600 flex fuel vehicles for every E85 station out  
5 there.

6 So, today we've got a large vehicle base that is  
7 relatively under-served. And in California, alone, if  
8 we were -- if those flex fuel vehicles all had adequate  
9 access and were using E85 regularly, we could displace  
10 about 255 million gallons of petroleum per year,  
11 starting right now.

12 So, yeah, our experience, you know, we are a --  
13 you know, we're a start up company a couple of years  
14 ago. We've received some very strong backing from some  
15 leading clean tech venture capital funds. We continue  
16 to get strong interest in what we're doing.

17 As we've mentioned before to this group, a big  
18 part of that is because we are a partner with -- you  
19 know, have been able to do a public/private partnership  
20 with the State of California to provide some of our own  
21 capital in combination with the grant programs that  
22 are -- that have been made available by the Energy  
23 Commission.

24 But I do want to also note that it's -- while we  
25 get a lot of interest by the private sector, the

1 importance of these grants to this program is key. And  
2 because the programs are available we are able to  
3 attract the private capital as match. But this market  
4 really is in the very early stages, volumes are still  
5 relatively low and continuing public/private partnership  
6 is very important in this market to help mitigate the  
7 risks and the costs of the equipment.

8           Some things that we have learned here, in  
9 California; the installation costs that we've  
10 encountered in the State can vary widely, from somewhere  
11 in the neighborhood of \$275 to \$375 thousand dollars  
12 depending on the configuration of a station site, the  
13 amount of work that needs to -- that needs to take place  
14 to put in all new infrastructure to be able to handle  
15 these fuel types.

16           So, we've taken an approach where we -- we bring  
17 entirely new equipment to the site. We're not in the  
18 business of retrofitting existing equipment because we  
19 want to make sure that we comply with UL requirements  
20 and, you know, with all of the regulations.

21           One thing that we have noticed in working with a  
22 grant program is the cost of Davis-Bacon Act compliance  
23 are significant. We've been encountering costs as high  
24 as \$45,000 of additional cost in terms of labor, so  
25 that's been one of -- one key challenge with regard to

1 getting these stations completed on a reasonable budget.

2           The other, and this is really what, you know, I  
3 want to talk about today is some of the -- there are a  
4 lot of challenges with regard to permitting, because in  
5 many of the jurisdictions that we enter it's the first  
6 time that the fire marshall, and health and safety, and  
7 other folks have had an opportunity to work with a  
8 renewable fuels company on these new types of fuels, so  
9 there's a lot of education that's required.

10           The way that we do our business, being a  
11 separate retailer on the same site, also creates some  
12 minor challenges, just making sure that we're  
13 coordinated well in the regulatory databases, et cetera.

14           But the biggest thing that we've run into is  
15 that this is still very much a municipality by  
16 municipality type of permitting operation, it's a brand-  
17 new process every time. And, you know, the learning  
18 curve for each of these agencies is quite steep.

19           And one of the things that we're looking at is,  
20 you know, finding ways to work with the State agencies  
21 to help -- to help provide educational materials to the  
22 local folks, and provide some leadership and guidance on  
23 what it takes to get new fuels implemented in new  
24 infrastructure today.

25           Another challenge that we run into on

1 permitting, that does delay the process, as many of --  
2 many station owners today currently have issues with  
3 compliance with local regulations, they're out of  
4 compliance for some things that they've done. And  
5 because of that the process gets slowed down a little  
6 bit until site owners come up to compliance.

7           And, finally, you know, these local authorities,  
8 under the conditional use permits, have broad latitude  
9 in being able to hold up a process. And so, again, we  
10 think education is really important, but hitting that  
11 conditional use permit in almost every site that we're  
12 at adds significant complexity and time to the build  
13 schedule.

14           So, we've been making, as a company, great  
15 progress, we feel, in breaking down some of those  
16 barriers, but they are real and they do exist.

17           You know, these -- I guess the key here is that  
18 this is new, it's the first time that most contractors,  
19 inspectors, people with agencies have ever dealt with  
20 these issues and that adds a lot of time and cost to the  
21 job.

22           So, things that we are looking for is the  
23 additional support from some of the State agencies to  
24 help streamline that process and get some better  
25 education out to the local agencies.

1           We have found that when we do make the fuels  
2 available that the customers love it. We've been seeing  
3 a pretty strong response. And we've really found three  
4 keys that we have learned from our customer base.  
5 Consumers need access in convenient locations. They're  
6 not going to drive, you know, too far out of their way  
7 and they don't want to go behind the fence in, you know,  
8 a fleet yard somewhere to find their fuels.

9           So, we need to make these fuels available in  
10 places that are convenient for customers. People have a  
11 lot of questions about these fuels and so providing them  
12 with confidence that there's a company that stands  
13 behind the fuel, that it's a high-quality product is  
14 really important and that we'll be with them to help get  
15 them through any issues that may come up, and provide  
16 them with really good customer service has been real  
17 important for us.

18           And we've learned a few things about the value  
19 equation for consumers. On the biodiesel side, we know  
20 there is a small population that's willing to pay a  
21 premium, but it is a very small population.

22           The general public really doesn't -- is not  
23 interested in paying much of a premium for diesel  
24 replacements.

25           For E85, we also do know that we need to be able

1 to offer a strong value proposition, a significant  
2 discount to the price of gasoline to make sure that  
3 customers that experience some mileage drag are still  
4 getting good value for their money.

5           And we do think that continuation for high  
6 level -- or for support of high-level blends, from a tax  
7 stand point, is continuing to be very important while  
8 this fuel gets established and becomes more mainstream.

9           So we, as a company, are looking at lots of ways  
10 that we can supplement the income from -- you know, from  
11 the station assets we're putting in place. We're  
12 getting involved in some limited bulk and commercial  
13 fuel sales. We're active in the markets for trading and  
14 sales of rims.

15           We are very interesting in seeing how the low-  
16 carbon fuel standard market develops in terms of credit,  
17 sales, and other opportunities there. I think that can  
18 provide a strong additional financial support for these  
19 products, and we're looking into other -- other new fuel  
20 types, both blends and types of fuel to be able to offer  
21 it to customers.

22           So, one of the questions that was asked of us is  
23 what does -- you know, what does the future look like  
24 for renewable fuels and E85, in particular, retail in  
25 California?

1           We think it's a very strong opportunity, lots --  
2 a good market opportunity that's growing, but it is  
3 still small today.

4           We do feel like we're making great progress on  
5 understanding the customer better and understanding the  
6 return on investment from these stations. But it is a  
7 market that's absolutely in its infancy. You know, we  
8 are working with customers to make transitions and they  
9 are -- we are working with an infrastructure that's been  
10 in place for, you know, many decades in most cases.

11           And we think that we can achieve a pretty rapid  
12 pace of change here in the State, but the incentives  
13 that the Energy Commission has put into place are going  
14 to continue to play an extremely important role in  
15 driving the adoption of renewable fuels infrastructure.

16           So, a couple of things, just final thoughts on  
17 how, you know, this body can help. We would welcome the  
18 opportunity to work with other agencies to help -- help  
19 endorse this kind of program to municipalities, to help  
20 them understand the importance that it has for the  
21 Energy Commission and the State of California.

22           Continued support from AB 118 is very important  
23 to E85 in California.

24           We are also, unfortunately, engaged in a very  
25 heated debate at the national level about ethanol, and

1 the role that it will play going forward. We think  
2 California has shown strong leadership. It's been very  
3 helpful to me, and our company, as we're in Washington  
4 to talk about the leadership California's showing on E85  
5 and renewable fuels.

6 And any opportunities to help weigh into that  
7 debate I think would be very -- it would be greatly  
8 appreciated.

9 We also have a situation in California where we  
10 have thousands of flex fuel vehicles that the State  
11 owns. We've developed a partnership with the Department  
12 of General Services, but some continued assistance with  
13 those State vehicles to make sure they're aware of where  
14 the outlets are would be of help.

15 And, again, working with municipalities and  
16 agencies not only on permitting issues, but helping them  
17 become a customer, in the same way that the State has  
18 been a great customer for us, would also be greatly  
19 appreciated.

20 So, with that I've reached the end of my  
21 comments today. I don't know if we have any question  
22 time or --

23 MR. WENG-GUTIERREZ: Yeah.

24 MR. HORTON: Okay, great.

25 MR. WENG-GUTIERREZ: So, if there are any

1 questions from the dais?

2 VICE CHAIR BOYD: A quick question, Matt. I  
3 don't know if you were here this morning when I broached  
4 the question about biodiesel versus renewable diesel and  
5 whether biodiesel really -- whether it had a big future.  
6 And I just wondered if you had any views on biodiesel,  
7 and recognizing just like ethanol E-10, California,  
8 versus E-15 desires, and in some parts of the nation,  
9 biodiesel has the same percentage hurdles; warranties by  
10 manufacturers, other concerns.

11 Do you -- what do you see going on in the  
12 biodiesel arena, in particular?

13 MR. HORTON: That's a great question. Our  
14 company actually got started focused on biodiesel, so  
15 it's near and dear to our hearts, and we've really grown  
16 up as a company with biodiesel. We're aware of the  
17 limitations that exist, but we think it does have a --  
18 continues to have a strong future.

19 Because of some of the limitations that you  
20 mentioned we are very interested in participating in  
21 demonstrations and pilot programs to learn about renewal  
22 diesel, we think it does offer some -- you know, some  
23 attractive opportunities in the way of higher blends and  
24 compatibility with the existing vehicles today.

25 So, today, you know, we -- I would say much like

1 on the ethanol side, we have an eye toward the future,  
2 cellulosic ethanol, other advanced ethanols, ethanol  
3 products. You know, we think that the business for  
4 biodiesel is strong, pretty strong at present, but may  
5 transition over time to other fuel types.

6 And our commitment to our customers is we want  
7 to provide them the most sustainable fuels that meet  
8 quality and cost targets.

9 VICE CHAIR BOYD: Okay, thank you.

10 Any questions from the audience, since this is a  
11 panel of one?

12 MR. WENG-GUTIERREZ: I think we have a staff  
13 question.

14 VICE CHAIR BOYD: Guess not. Thanks Matt.

15 MR. SCHREMP: Gordon Schremp, Senior Staff.  
16 Matt, I have a couple questions for you.

17 Are your -- is your companies activity at these  
18 existing sites, through a lease arrangement, are you an  
19 obligated party under RFS2 regulations, as well as an  
20 obligated party under LCFS regulations?

21 MR. HORTON: We are not obligated under -- we  
22 are not an obligated party under RFS, so we view  
23 ourselves as essentially a source of compliance for  
24 those who are because we do generate a tremendous number  
25 of RIN credits, and view ourselves as a natural partner

1 in that opportunity.

2 With regard to the low carbon fuel standard, you  
3 know, we're very sort of interested to see how it's  
4 going to -- how it will -- how it's taking shape and  
5 what the opportunities are there for, again, being a  
6 compliance opportunity for partners that are obligated.

7 MR. SCHREMP: And I guess a final question is I  
8 noticed that for your customers dealing with or having a  
9 correct, or appropriate price for E85 to deal with the  
10 fuel economy difference, how does -- how does Propel  
11 feel about maybe providing enough information to  
12 consumers and along the lines of, say, fuel economy  
13 equivalent pricing for 85, recognizing there are some  
14 variabilities in the 85 blends, and seasonality of  
15 gasoline energy contents.

16 But how would you feel as a company about trying  
17 to provide some additional information to consumers  
18 along those lines?

19 MR. HORTON: Yeah, good question. Yeah, we've  
20 actually found that our consumers are fairly educated on  
21 the issues. People who drive flex fuel vehicles and  
22 have any experience with E85 understand, you know, the  
23 lower BTU content. Certainly, there are some that may  
24 not.

25 We think the right thing to do is to educate

1 customers on that. We think it's in their best  
2 interest, and ours, and as an industry to make sure that  
3 we have an educated consumer base. So, yeah, it's  
4 something that we do try to educate consumers on, yeah.

5 MR. SCHREMP: Thank you. Do you have a  
6 question?

7 MR. STEVENSON: Just a question. Dwight  
8 Stevenson, with Tesoro. So, you do blend the ethanol  
9 and base fuels together?

10 MR. HORTON: So, today we're not doing blending,  
11 ourselves --

12 MR. STEVENSON: You aren't, okay.

13 MR. HORTON: -- we're purchasing a pre-blended  
14 fuel.

15 MR. STEVENSON: Okay, thank you.

16 MR. WENG-GUTIERREZ: Perfect. Thank you so  
17 much.

18 And next we'll be going to Jim Uihlein, from  
19 Chevron. Is he online?

20 MR. UIHLEIN: Okay, hi, thank you for the  
21 opportunity to talk to this group today. I'm going to  
22 be talking a bit about some experiences that Chevron  
23 picked up in doing an E85 demonstration program here, in  
24 California.

25 Flip over to the next slide. The demonstration

1 program was done in cooperation with both the Air  
2 Resources Board and CalTrans, we were providing E85 to a  
3 test fleet of FFVs at two different locations that  
4 CalTrans had, both of them being fleet locations. One  
5 was in Oakland, the other one was in Marysville.

6 We provided fueling equipment. It wasn't really  
7 completely retail compatible. It consisted of an above-  
8 ground storage tank, with an associated dispenser and  
9 then, of course, a hose and nozzle also associated with  
10 that.

11 It was more of a temporary installation. The  
12 dispenser was kind of approaching retail ready, but  
13 we -- given that it was a fleet location, behind the  
14 fence, we went with what worked for that environment.

15 One of the things we did run into in providing  
16 the equipment for that was the discovery that there were  
17 no certified E-85 enhanced vapor recovery systems  
18 available, and so we had to go with a dispenser that  
19 lacked that sort of vapor recovery system on it.

20 The next slide. Our goals in this program, just  
21 speaking from Chevron, was number one to assess vehicle  
22 performance and customer acceptance as part of that. We  
23 were looking at things like mileage and emissions, of  
24 course.

25 We're looking at how the vehicles performed and

1 it was a couple-year program, and so we had an  
2 opportunity to get observations over the range of  
3 seasonal conditions.

4 It was also long enough that there was an  
5 opportunity to get data on maintenance needs and, also,  
6 how the driver responded to the use of the fuel.

7 For our part, of course, we're also very  
8 interested in investigating some of the aspects of  
9 delivering E85 to a customer installation, in terms of  
10 blending, and transportation, and dispensing it to the  
11 vehicle.

12 And so, naturally, the activities that we were  
13 directly involved with around the blending and  
14 transportation we have a lot of information.

15 Of a lot of the other information, more on the  
16 vehicle performance side, the Air Resources Board has  
17 that information. We don't have access to it at this  
18 point.

19 There's a final report that we understand is  
20 underway at ARB, but it has not yet been released.

21 We think that in addition to our interest in  
22 finding out some of these things about the program, we  
23 also think it would be a useful source of information  
24 for IEPR. And so anything that the Energy Commission  
25 could do to help expedite that report out of ARB would

1 be very helpful and very much appreciated.

2 The next slide. One of the aspects I wanted to  
3 talk about specifically with our experience in providing  
4 E85 in the State was what we had to go through in order  
5 to blend an on-spec product.

6 And the biggest issue that we were confronted  
7 with was that if you add CARBOB and ethanol you don't  
8 get an on-spec E85 at any of the blend ratios that are  
9 permitted by ASTM.

10 The ASTM 5798 spec is really the standard for  
11 E85, or what ASTM refers to as an E72 E85 fuel. And DMS  
12 enforces the ASTM within the State.

13 It covers a lot of properties, but the two that  
14 we're really concerned about with this particular issue  
15 were RVP and the minimum ethanol content.

16 And just to give an example of what we were  
17 faced with; in the summertime the E85 spec is a 5.5  
18 minimum RVP. CARBOB runs a little bit above that,  
19 generally, but -- and pure ethanol has an RVP of 2.3  
20 pounds. And so when you mix those together, depending  
21 of -- at a ratio of 15 percent CARBOB, 85 percent  
22 ethanol, you end up with an RVP of somewhere in the 4  
23 and a half to 5.3 range, a little bit below spec, but  
24 really never -- never actually getting up to the spec.

25 And I should note that while the pure ethanol

1 RVP is 2.3, everything we used is, of course, denatured,  
2 and so the actual RVP of the denatured ethanol will  
3 depend somewhat on the nature of the denaturant. If  
4 it's something like a natural gasoline, it may have a  
5 little bit higher RVP. If they use a normal gasoline or  
6 a BOB, it would be something lower than that. That  
7 tends to range from 4.5 to 5.3, that we would actually  
8 observe.

9           The next slide. So, there were -- are a couple  
10 of options to increase the E85 RVP in order to get it  
11 on-spec. One thing you can do is increase the  
12 proportion of hydrocarbon to make it a bit less than 85  
13 percent.

14           The other option is to try to increase the RVP  
15 of the hydrocarbon using a third component, which is  
16 what we ended up choosing to do for this particular  
17 exercise.

18           The ASTM specs at the time were fairly rigid and  
19 so there wasn't a whole lot of wiggle room for  
20 increasing the proportion of hydrocarbon. I'll talk  
21 about that a little bit later. But it was just easier  
22 to try to use a third component to help pressurize the  
23 hydrocarbon.

24           We chose isopentane just because we had it  
25 available. We got a little pressurized tank that was

1 actually like on a trailer that we would use to pressure  
2 up the batches as we blended them into a truck.

3 Blending results over the course of the program,  
4 we had to add somewhere between two and a half to 6.8  
5 percent isopentane. The two and a half was kind of a  
6 one one-off. We average around 5.2. So, it was a fair  
7 amount of isopentane to add in there in order to get it  
8 up to pressure.

9 The next slide -- ah, thank you. The commercial  
10 implications of all this is that if you look at the  
11 current terminal infrastructure, it's really fully and  
12 efficiently utilized. They've got tanks for CARBOB,  
13 they've got tanks for ethanol, but there's nothing there  
14 for a third component.

15 The other aspect of this is that the third  
16 component can't use just any old tank because naturally  
17 what you want to increase the vapor pressure of this  
18 stuff is something that possesses a fairly high vapor  
19 pressure, and so it's going to require pressurized  
20 storage of in order to get it into the terminal.

21 And, actually, when you look at the available  
22 pressurants that you might use, butane has some  
23 advantages and that, you know, typically that would be  
24 in a sphere type storage in bulk applications, that you  
25 may be able to do something with rail cards for this.

1 But in any event, it's not going to use an ethanol or a  
2 CARBOB tank.

3           The other aspect of this is right now terminals  
4 aren't in the business, generally, of blending to  
5 specifications. They handle volumes and volume ratios  
6 really, really well, but that presumes that you can give  
7 them, you know, the right volume and/or the ratio and  
8 they'll hit it with a high degree of accuracy.

9           Something like this is really a finished product  
10 blending to a spec, more like we do in the refinery,  
11 which is not typically a terminal operation at this  
12 point.

13           Then the variations come in both the ethanol  
14 denaturant, as I mentioned, affecting the ethanol RVP  
15 and variations in CARBOB.

16           And so blending to hit a spec and monitoring to  
17 make sure that you hit that spec in the final product,  
18 again, is somewhat foreign in the terminal environment  
19 at this point.

20           And the next slide. Also, the other thing  
21 that's happened since our demonstration program is that  
22 ASTM has made some changes to the D5798 standard.  
23 They've relaxed the minimum percent ethanol somewhat.  
24 It's now 68 percent year-round, which means that  
25 effectively the E85 is somewhere between 68 and 83

1 percent ethanol. That helped. But when you look at the  
2 situation in California, it doesn't eliminate the need  
3 to do third-component blending, it just reduces the  
4 amount of whatever that third component is that you'd  
5 need to use. You would still have the infrastructure  
6 requirement to try to set up to do terminal blending of  
7 E85 in the State.

8           ASTM is also considering a shift to a flexible  
9 fuel specification, rather than a strictly E85 or, as I  
10 mentioned, E72 E85 specification.

11           This would drop the minimum ethanol content down  
12 to 51 percent year-round and that brings you very close  
13 to being able to blend this flex fuel vehicle fuel  
14 without using a third component.

15           There's still an issue or two in shoulder  
16 months, where the seasonal specs for the E85 don't  
17 completely match the gasoline that's available, that you  
18 would expect -- or, rather, the CARBOB that you would  
19 expect out in the field.

20           But the third component blending would result in  
21 what we currently think of as E85 containing somewhere  
22 between 51 and 75 percent ethanol. So, it would be  
23 pretty short of E85 at that point. And that, again,  
24 would depend on the season, with the summer getting some  
25 of the lower concentrations when most of the driving

1 gets done.

2           So, I guess the main points that I was trying to  
3 relate from our experience is that retail infrastructure  
4 is really not the only infrastructure issue for E85.  
5 We've also got some issues at terminals, to be able to  
6 set up if this were ever to be done on a large scale.

7           And even if the ASTM standard changes, that  
8 alternative would be to produce a flex fuel vehicle fuel  
9 at lower levels, but then that ends up increasing the  
10 volumes required to move the same amount of ethanol, you  
11 know, for compliance with things like RFST2 and the  
12 LCFS. And it also makes other problems, like the lack  
13 of FFVs in the State even more limiting.

14           And with that, I'll take any questions.

15           VICE CHAIR BOYD: Thank you. Questions?

16           Gina and then I think Gordon has questions, as  
17 well.

18           MS. GREY: Gina Grey, from WSPA. I think this  
19 is a question probably more for Mr. Horton, but Jim's  
20 presentation kind of triggered this question relative to  
21 changes in ASTM.

22           I know that ARB has been, over the last year or  
23 so, proposing some changes to the E85 specifications and  
24 we, as WSPA, for one, have submitted comments on that  
25 mainly along the lines that, you know, ARB should

1 probably just go along with ASTM and not create a whole  
2 new set of specifications for E85 in California, that  
3 are different from the rest of the nation.

4           So, I guess to Mr. Horton, what would ARB's  
5 changes to the E85 specifications do, do you think, to  
6 the prospects for E85 in California.

7           And if you're not familiar with what they are  
8 proposing, I have written down here, I guess, changing  
9 the RVP and also changing the limits on benzene,  
10 aromatics, olefins, and sulfur.

11           Sorry. Yeah, go ahead.

12           MR. HEYDORN: So, I guess the way that I would  
13 address the issue or the question, and it's a good, is,  
14 you know, again, we think -- we look at this segment of  
15 the industry as just barely emerging, just getting on  
16 its feet. And the, you know, changes that a new spec  
17 might require in terms of, you know, the boutique fuels  
18 and things that would be required to meet spec, would  
19 make it even more challenging for E85 to be cost  
20 competitive as a motor fuel.

21           So, yeah, our strong preference at this point  
22 is, you know, to maintain sort of the test fuel type of  
23 exemption we're operating under until the volumes get to  
24 be large enough that the infrastructure is efficient in  
25 delivering whatever blend stocks are required.

1           MR. SCHREMP: And then I just have a -- this is  
2 Gordon, I have a clarifying question for you. So, under  
3 your test program for marketing these fuels, essentially  
4 the E85 is created by starting with an E10 blend and  
5 then adding E99 until it gets up to an E85 spec. Is  
6 that sort of how it's created versus the dynamic that  
7 Jim Uihlein described in how they created E85?

8           MR. HEYDRON: To be honest, I'll probably need  
9 to defer the question to some of our more technical  
10 folks. Jim, can you -- yes? Yes. Yes.

11          MR. SCHREMP: Thank you.

12          MR. WENG-GUTIERREZ: If there are no other  
13 questions from anyone online, or in the room?

14          Okay. I had one quick question for Jim. I  
15 just -- you had mentioned an ARB report that we might to  
16 get a hold of. Do you have a contact name for that  
17 person or who were you working with?

18          MR. UIHLEIN: Probably the best person to talk  
19 to would be Mike Waugh because it's in the fuel section.

20          MR. WENG-GUTIERREZ: Great, he's here today, so  
21 we'll catch him before he leaves.

22          MR. UIHLEIN: I didn't -- nobody tipped me off  
23 on that one, either.

24          (Laughter)

25          MR. WENG-GUTIERREZ: All right. Thank you, Jim.

1           VICE CHAIR BOYD: Thank you very much.

2           MR. WENG-GUTIERREZ: And next we'll have Eric  
3 Bowen come up and speak.

4           MR. BOWEN: Good afternoon everyone. I'd like  
5 to thank Commissioner Boyd and the Energy Commission for  
6 inviting me here to speak today. My day job is with  
7 Renewable Energy Group, the nation's largest producer  
8 and distributor of biodiesel, about 20, 25 percent  
9 market share.

10           One of the things I do in my volunteer time is  
11 serve with the California Biodiesel Alliance, I'm the  
12 Chairman of our State Trade Association here in  
13 California for biodiesel.

14           Before I get into my presentation, I'll start  
15 with you, Commissioner Boyd, and I greatly appreciate  
16 the interest that you've taken in trying to figure out  
17 the answer to what is the future of biodiesel? You've  
18 asked that question, I think, two or three times now  
19 and, you know, we've met before and discussed this.

20           And I guess I think that John got it right when  
21 he said that both will be here for a while. And I think  
22 Matt also got it right when he said we don't know what  
23 the future holds, but we're going to take what the  
24 market has available and customers are asking for today,  
25 which is biodiesel.

1           And I suspect from our prior conversations, and  
2           conversations I've had with staff, that part of your  
3           questioning is motivated by what's the most effective  
4           and efficient use of limited State resources and should  
5           any of those go towards biodiesel, not knowing what the  
6           future of that fuel may be.

7           So, I've posited that the future of biodiesel is  
8           strong and it will be with us for quite some time. But  
9           I'm also willing to say that should I be wrong, and I  
10          don't think that I am, you actually don't have, I think,  
11          the problem that you think you have.

12          All of the infrastructure for biodiesel that  
13          would give the State the biggest bang for the buck would  
14          happen at the terminal, and it's about segregated  
15          storage at the terminal and ability to blend that fuel  
16          into petroleum diesel.

17          Renewable diesel is going to need that exact  
18          same infrastructure. So, if we don't build it today for  
19          biodiesel, it won't be there tomorrow for biodiesel or  
20          renewable diesel.

21          So, you know, we've got 50 some terminals around  
22          this State. And as Jim Uihlein mentioned in his  
23          presentation, one hundred percent of those have  
24          infrastructure for gasoline and for ethanol, and we can  
25          create low blend and high blends of ethanol. And

1 there's some limitations on the high blends that he  
2 highlighted, I think quite effectively.

3           Not one of those has storage for a renewable  
4 diesel fuel, whether it's a biodiesel or a hydro-treated  
5 renewable diesel. And because of that it's extremely  
6 difficult for biodiesel to enter the petroleum fuel  
7 supply stream, or just dropt the word "petroleum", the  
8 fuel supply stream.

9           And California really lags the nation in this  
10 regard. Other states have put that infrastructure in  
11 through both private and public investment, and where  
12 that is there are thriving biodiesel markets.

13           And so we're, I think, really missing an  
14 opportunity to improve California's energy independence,  
15 as well as reduce California's carbon emissions through  
16 the diesel fuel pool by not investing in that  
17 infrastructure.

18           And I'll get into that a little bit more, but I  
19 wanted to start by directly addressing your questions,  
20 Commissioner Boyd, and letting you know that you can  
21 take comfort and money will be well spent for both  
22 fuels.

23           VICE CHAIR BOYD: Thank you. I knew I'd set you  
24 up pretty good there.

25           MR. BOWEN: I appreciate it.

1           I mentioned California Biodiesel Alliance, the  
2 State's -- so, four things I want to touch base on here  
3 today, and I've been asked to speak about biodiesel fuel  
4 quality and storage issues.

5           First, I want to say that fuel quality has never  
6 been higher, and I'll get into what I mean by that here,  
7 shortly.

8           Second, I want to let the Commission know and  
9 the audience know that biodiesel is back in a big way  
10 based on RFS2, and it looks very, very different than  
11 the biodiesel industry that you probably think you know;  
12 massive consolidation, rationalization, and  
13 professionalization of the industry.

14           California lags the nation, and why I think why  
15 we have an impression of biodiesel circa 2007 or 2008,  
16 because of this lack of infrastructure that we've been  
17 talking about, as well as this regulatory uncertainty.  
18 And I'll spend some time getting into those two topics.

19           And the good news here is that these are  
20 actually comparatively inexpensive problems to fix.

21           So, first off, biodiesel fuel quality. I think  
22 it's fair to say that biodiesel is now a drop-in fuel,  
23 and this is a big deal. Biodiesel is as much a drop-in  
24 fuel as low blends of ethanol.

25           In 2008 ASTM changed the definition of diesel

1 fuel, D975, to include up to five percent biodiesel.  
2 Biodiesel can be shipped in pipelines, those that do not  
3 have jet fuel. Unfortunately, that's a limited  
4 California opportunity, but that's a huge national  
5 opportunity and biodiesel is shipped in pipelines today.

6           And all of the engine manufacturers, through the  
7 ASTM consensus process, have all approved B5 with  
8 theirs. Many engine manufacturers have approved B20 and  
9 we're adding more and more to that list every day, and  
10 there are some engine manufacturers that even have  
11 approvals above that.

12           So, the point being that, yes, today there is  
13 somewhat of a blend wall at five percent. Even that is  
14 an enormously large opportunity that we're not taking  
15 advantage of.

16           It's reasonably foreseeable to see that blend  
17 wall increasing to 20 percent in the short future, and  
18 there will always be NISH applications, mining,  
19 agricultural, particularly environmentally sensitive  
20 fleets that can use even higher blends, as you know  
21 well, Commissioner Boyd, all the way up to pure  
22 biodiesel or B100.

23           So, how has RFS2 changes the industry and what  
24 does this mean for what it is to have the new biodiesel  
25 industry?

1           So, I want to do a couple quick corrections from  
2 John's presentation this morning, just to make sure that  
3 we're all operating under good, current, correct  
4 information.

5           The RFS2 requirement for 2011 is 800 million  
6 gallons of biomass-based diesel, and that's biodiesel or  
7 renewable diesel. And that has to have at least a 50  
8 percent carbon reduction or qualify as an advanced  
9 biofuel under federal rules. USEPA and CARB think about  
10 that a little different, so soy biodiesel qualifies  
11 federally, while that would not qualify as an advanced  
12 biofuel here in California.

13           That increases to one billion gallons next year  
14 and then EPA has discretion to increase it thereafter.

15           In addition, because biodiesel is defined  
16 federally as an advanced biofuel, it also participates  
17 in the bucket of generic advanced biodiesel, where  
18 cellulosic ethanol also participates.

19           But unlike cellulosic ethanol, where there  
20 really is no commercially available quantities, we're  
21 talking about hundreds of millions of gallons, over a  
22 billion gallons of installed production capacity in the  
23 United States, today, of biodiesel.

24           I was asked to address what role of imports --  
25 I'm using BD here for biodiesel, RD for renewable

1 diesel. I think biodiesel imports may come in, but  
2 we're not seeing a lot of that today, and we'll wait and  
3 see how that develops. That has a lot to do with  
4 registrations and being RFS2 compliant.

5 Renewable diesel, we may see some of Neste's  
6 product, but quite frankly I think it goes to Europe and  
7 Asia, we probably do not see it here. We also don't  
8 have the marine infrastructure to take it in.

9 And sugarcane ethanol, once all the ethanol  
10 stuff gets rationalized, we probably will see.

11 With regard to California LCSF, there's an  
12 opportunity for obligated parties, several of which are  
13 in the room here today, to double dip their compliance  
14 requirements through RFS2 and California LCSF by meeting  
15 their RFS2 requirements here in California.

16 I view this as a good thing. Normally, we think  
17 of a double dip as a bad thing. In this context it's a  
18 good thing because it allows California to lead the  
19 market with these clean renewable fuels, and we really  
20 need to be more actively thinking about how we do that,  
21 and I know today's meeting is a lot about that.

22 Unlike RFS2, which has specific buckets for  
23 fuel, the low carbon fuel standard is market-based, so  
24 it's less clear what fuels will be used. And I really  
25 think that's what's been motivating some of Gina's

1 comments to the electricity providers, and others, of  
2 who's going to come into LCFS, what are these credits  
3 going to look like?

4 Because if you're an obligated party, nationally  
5 you know you've got to have your portion of the 800  
6 million gallon biomass-based diesel mandate, that's  
7 pretty clear.

8 In California, you don't know what you have to  
9 have and so we need to figure this out. Several of us  
10 in this room, actually, including myself, sit on the ARB  
11 Advisory Panel, trying to figure this stuff out. But  
12 it's going to be a while before LCFS is a true market  
13 driver of clean fuels in California is my personal  
14 opinion.

15 So, getting to the point, again, about  
16 leadership and market opportunity here, if we did just  
17 B5 in California, and we just did that across the State  
18 and, you know, the states like Illinois are already  
19 doing B11, so this is not a hard thing to envision or to  
20 actually accomplish.

21 If we just did a B5 here in California, and we  
22 did that from waste feed stocks, used cooking oil,  
23 inedible corn oil, animal fats, that's about 160 million  
24 gallon per year opportunity here in California, easy for  
25 the biodiesel industry to supply that volume of

1 biodiesel. And that would represent a four percent  
2 carbon intensity reduction on that diesel. And this is  
3 overnight, this is low-hanging fruit, this is stuff that  
4 we should be doing.

5           As that blend wall gets increased and we go  
6 towards B20, you can see a 15 to 18 percent CI reduction  
7 in the petroleum diesel. Our goal for 2020 is ten  
8 percent in the fuel pool. We can do this on the diesel  
9 side quite easily, I think, over a five-year period, if  
10 we put some effort into it on getting everything up to  
11 B20.

12           So, again, do I think we'll get there? Not  
13 without a lot of effort. If we wanted to get there, do  
14 I think it can be done? The answer is absolutely yes,  
15 those volumes are available, those CI reductions are  
16 available.

17           So, what is holding back the market? Well, I  
18 opened up with it, so it's lack of infrastructure.

19           So, terminal storage is priority one, two and  
20 three. The second is how do you get the fuel into that  
21 terminal storage?

22           There's a lack of available rail off-loading,  
23 and a lot of it, I think, is monopolized by the ethanol  
24 coming in. But we've got to figure out that piece of  
25 how do you get fuel into the terminal after you've put

1 the tank there.

2 Then, of course, you need rack blending, and  
3 then I'll get into the UST issue here a little bit  
4 later.

5 Then on the regulatory uncertainty side I know  
6 there's been comments coming out of CARB about concerns  
7 about NOx, and I want to get into that in more detail  
8 here, shortly.

9 And then I've already indicated low carbon fuel  
10 standard is not sending any clear market signals.

11 For renewable diesel, the real holding back  
12 there is costs, and it's both a capital cost and an Op.  
13 ex., and I'm more than happy to spend more time on that,  
14 but in the interest of time for now I'll just move on

15 So, what is this terminal opportunity? Well, as  
16 I said, biodiesel or renewable diesel is going to need  
17 terminal access to enter the fuel supply. With our 50  
18 terminals, not one terminal currently has this storage  
19 capacity.

20 That lack of infrastructure as a really material  
21 effect on the magnitude of 10 to 25 cents per blended  
22 gallon. So, if you're doing a B5, that's 10 to 25 cents  
23 extra, or a B20, 10 to 25 cents extra.

24 If you load all of that 10 to 25 cents on the B5  
25 portion, you're essentially multiplying that by 20 is

1 the cost penalty for that B100 that it has to achieve to  
2 have price parity with petroleum diesel. It's too much  
3 extra logistics cost for it to be able to handle.

4 On the other hand, if you had this  
5 infrastructure, you're talking 2 to 4 cents, almost  
6 immaterial.

7 And it's not a big investment, so my  
8 conversation with terminal owners, it looks to be about  
9 a 1 to 3 million dollar investment depending on the  
10 tank, the location, and permitting, all of those types  
11 of things.

12 So, you're talking about a 50 to 150 million  
13 dollar investment here. Well, the private sector would  
14 gladly do a 50 percent match on this. We get a really  
15 quick ROI on this and it's multiple fuel. It can be  
16 available for biodiesel, renewable diesel, any other  
17 distillate products that come down the road, so this is  
18 never going to be lost or sunk costs.

19 So, let's get into underground storage tank,  
20 because I know this has been a concern for folks. We  
21 can't do biodiesel because of the underground storage  
22 tank problem.

23 Well, first off, there's not an underground  
24 storage tank problem at B5, we dealt with that a while  
25 ago. And, secondly, there is a solution for the short

1 term on B20, through the variance program we put into  
2 place. The reason there was -- there was never concern  
3 about biodiesel causing a leak, there's not one known  
4 instance in the entire country, or even in Europe, of  
5 biodiesel causing a leak in an underground storage tank.

6 The problem was there was no UL approval, and  
7 California law required UL approval. So, you just  
8 couldn't get over that hurdle and you can't get UL to  
9 act quickly.

10 So, the Federal EPA is actually stepping into  
11 this void and going to help create some new programs  
12 that California should be able to piggyback on, that  
13 will solve this problem all the way up to B20. It isn't  
14 going to happen tomorrow, but it will probably happen in  
15 the next couple of years.

16 On the other hand, renewable diesel is no  
17 panacea. There is no ASTM definition of renewable  
18 diesel. There are unknown compounds in renewable  
19 diesel. And you can't put renewable diesel in an  
20 underground storage tank today, it's got more problems  
21 than biodiesel has.

22 So, I don't want us to think that there's this  
23 great fuel that can come down the road, renewable  
24 diesel, so we just need to wait for it and not support  
25 the fuel that's here today, which is biodiesel. The

1 reality is we need to support both and supporting both  
2 is actually complementary to both and not competitive.

3           So, let's get into NOx. So, the graph up here  
4 is the federal information and you'll see that  
5 essentially at most blend levels there's, essentially,  
6 no NOx increase. Most importantly, let's focus on B5 to  
7 B20.

8           Now, the reason this is true federally is  
9 because, as everyone in this room knows, there's a  
10 different standard for Federal ULSD than California ULSD.  
11 So, we have a higher cetane, lower aromatic diesel,  
12 which is a good thing. I'm an asthmatic, I like the  
13 improved air quality.

14           And when you add biodiesel to California diesel  
15 spec you see a slight -- you see, basically, no NOx  
16 increase here federally. You see a slight increase at  
17 some blend levels here in California, but we don't know  
18 what it is.

19           The science seems pretty clear and a number of  
20 people, both in the petroleum industry and the biodiesel  
21 industry are working on this, that blends up to be 5 or  
22 NOx neutral, and we should just acknowledge that and  
23 move on.

24           And then for blends of B6 and above, up to B20  
25 there might, emphasis on might, be a NOx increase

1 depending on the feedstock of the biodiesel. So, a low  
2 saturated biodiesel, made from a feedstock like a  
3 soybean oil, likely yes. So, you'd have to have some  
4 sort of NOx additive or cetane enhancer.

5 A high saturated biodiesel, like something made  
6 from a waste product, a used cooking oil or animal fat,  
7 has a very high natural cetane, probably has no NOx  
8 increase. And even if there was some that needed to be  
9 addressed, again, there's a very simple industry  
10 standard cetane enhancers, and NOx things.

11 So, the bottom line, all of this can be  
12 addressed.

13 The regulatory uncertainty that CARB has created  
14 has chilled the market, because if you're Kinder Morgan,  
15 you don't want to write a \$3 million check to put in a  
16 tank, to do biodiesel blending, not knowing what ARB's  
17 going to do about the future role of biodiesel in the  
18 California marketplace. So, we've got a real chilling  
19 effect going on.

20 But the reality is this is going to be solved in  
21 a couple of years and we need to be moving now to have  
22 the marketplace be ready.

23 So, what does this future state look like?  
24 There's a lot of biodiesel available, with a very low  
25 CI, from U.S. producers, with this drop-in opportunity

1 today to B5.

2 Renewable diesel will come. My company will be  
3 one of the ones that makes it. I want to be very clear,  
4 I'm pro renewable diesel. But it's not here today and  
5 it's not likely to come for a while, and it does have  
6 disadvantages over biodiesel from a cost stand point, so  
7 we need to figure all that out.

8 Virgin oils, the palms and the soys, will have a  
9 role to play, but they have higher CAs and higher costs,  
10 so everything's going to be waste in the early years. I  
11 bet you it's 50 percent of U.S. biodiesel production  
12 today is from waste materials.

13 Over 90 percent of the biodiesel my company made  
14 last year and, again, we're the largest producer in the  
15 country, waste materials. The industry has gravitated  
16 over to super high quality fuel from waste materials,  
17 driven by economics, clear and simple, they're lower  
18 cost feedstocks and you can still make great fuel.

19 But here in California there's an acute lack of  
20 infrastructure for renewable diesel and biodiesel, and  
21 we need to begin to invest in this infrastructure to  
22 take advantage of the opportunities to day on biodiesel,  
23 take advantage of the opportunities tomorrow on  
24 renewable diesel. And ultimately, down the road, the  
25 opportunities that, hopefully, you know, algal-oriented

1 fuels, both algal biodiesel and algal renewable diesel  
2 will present the State to increase and go into higher  
3 and higher blends of biodiesel.

4 I'd be more than happy to answer any questions.

5 VICE CHAIR BOYD: Just one question comes to  
6 mind about the lagging infrastructure here versus other  
7 states. Are the other states, and you mentioned  
8 Illinois, for instance, is not unlike corn has driven  
9 the Midwest, does -- do agricultural commodities like  
10 soy diesel, and what have you, is the farming of that,  
11 does that add added pressure in some of those areas to  
12 adopt programs that facilitate the -- that type of fuel,  
13 more than California?

14 MR. BOWEN: Added pressure, no. But are the  
15 agricultural roots the reason why? Yes.

16 So, it's my personal belief that all U.S.  
17 biodiesel policy started as ag policy, and that's why we  
18 have corn ethanol and biodiesel today. And that we  
19 wouldn't have a biodiesel industry where 50 percent is  
20 made from waste if it weren't for the early soy farmers,  
21 who put the money in to getting the biodiesel industry  
22 started.

23 So, those constituencies lobby their state  
24 legislatures to adopt pro biofuel policies. And then  
25 once those pro biofuel policies were in place, then the

1 market worked out about which biodiesel or which biofuel  
2 would enter the marketplace.

3           So, in Illinois, for instance, they have a sales  
4 tax abatement related to the quantity of renewable fuel  
5 in the petroleum, whether it's a gas or a diesel.

6           And so at a certain blend level it's just it  
7 makes economic sense to do that. Because that was  
8 financially more attractive for end users of fuel,  
9 sellers of fuel invested the millions of dollars  
10 required under the infrastructure to allow the seamless  
11 low-cost blending of the fuel into the supply stream.

12           So, was it ag pushing to make this happen? From  
13 a let's-support-our-domestic-economy, and support and  
14 raise the price of our agricultural crops by having them  
15 go not only into food, but also into fuel, absolutely  
16 yes.

17           But was that what specifically said let's put  
18 stuff into this terminal and let's use these fuels? No.  
19 Once the policy was established, the marketplace  
20 operated to support less expensive ways of getting the  
21 fuel into the marketplace more efficiently, and the  
22 market developed.

23           So, the California corollary should be LCFS.  
24 And five years from now you and I may be sitting down  
25 and talking about how LCFS actually did do that.

1           Today it's not the case, so it's a combination  
2 of policies, like AB118, and LCFS, and other things  
3 trying to get this whole marketplace going.

4           And so the message I'm trying to deliver here  
5 today is with the AB118 monies, and any other  
6 infrastructure related policies the CEC is considering,  
7 let's make sure that -- and, you know, there's  
8 opportunities up and down the supply chain I haven't  
9 mentioned. But the one place that all the fuel has to  
10 go through is the bulk terminal, and that's the one  
11 place where no biodiesel or renewable fuel exists today,  
12 and that's where we can get the biggest bang for our  
13 buck, and it's long-term infrastructure that will  
14 benefit the State for decades to come.

15           VICE CHAIR BOYD: Thank you.

16           MR. BOWEN: So, detropha is an interesting  
17 potential feedstock for both biodiesel and renewable  
18 diesel. Every detropha project that I personally have  
19 had contact with over the last eight years has not met  
20 its initial promises.

21           Will that always be the case for detropha or  
22 will someone figure out how to successfully farm  
23 detropha so that it can become a new feedstock for  
24 either biodiesel or renewable diesel? I will say I'm  
25 hopeful that someone will.

1           And then whether it becomes a feedstock for  
2 biodiesel or renewable diesel will simply be a factor of  
3 which of those two fuels can most economically compete  
4 for that feedstock source, and we'll wait and see how  
5 the market plays out.

6           MR. SCHREMP: Thanks Eric. I have a -- this is  
7 Gordon, I have a quick question for you.

8           Because your company's experienced using --  
9 converting waste material into diesel, could you provide  
10 us with sort of some contextual boundaries of supply  
11 potential from waste material in the U.S., and from  
12 waste material here in California, give us some context?

13          MR. BOWEN: Yeah. So, we believe the waste  
14 available in California is about 75 million gallons of  
15 waste feedstocks. Those, obviously, are going into  
16 other uses, including export today.

17          So, what portion of that can you capture? You  
18 know, is it 50 percent, 60 percent, 70 percent? You  
19 know, pick your number.

20          The biodiesel plants that are already built in  
21 California today, by and large, with really only one  
22 notable exception, are built to run waste feedstocks.  
23 And, you know, that total production capacity is -- call  
24 it somewhere between 50 and 70 million gallons per year.

25          So, probably right-sized for the feedstocks we

1 have available.

2           Nationally, it's a billion gallon plus  
3 opportunity on the waste feedstocks. And if -- you  
4 know, the one thing about waste that always causes us to  
5 pause is, hopefully, waste isn't growing, so there's a  
6 limited amount of these feedstocks.

7           And the answer is, yes, there is a limited  
8 amount of these feedstocks but, actually, there's a  
9 major new waste byproduct feedstock coming online to the  
10 tunes of hundreds of millions of gallon a year, and  
11 that's the inedible corn oil, which is a byproduct of  
12 corn ethanol making, and it's pulled off of the DDGs.

13           And there's -- you know, there's tens of  
14 millions of gallons of this product available today. We  
15 make a lot of biodiesel from that product, it makes a  
16 really nice fuel.

17           And there's been recent announcement from POET  
18 and others that leads us to believe that there will be  
19 hundreds of millions of gallons of new waste feedstock  
20 coming to market. So, it is a large available pool of  
21 supply that can be used nationally and come here to  
22 California.

23           MR. BRAUTIGAN: John Brautigan, with Valero.  
24 Thank you for correcting, I had misstated the number. I  
25 had said 600, it's 800, which even intensifies my

1 concern that the EPA is only showing 300 to 400 million  
2 gallons a year rate of biodiesel RINs being generated in  
3 this year.

4 I disagree a little with you on some of your  
5 renewable comments. I'm a proponent of renewable  
6 diesel. I think we know exactly what the compounds are,  
7 they're the same compounds as petroleum diesel. There  
8 might not be a spec for ASTM R100, but if you put  
9 renewable diesel R5, up to R5, because if you go over R5  
10 you have to have the FTC labeling. But up to R5 can go  
11 right into D975. It is -- it's diesel, it can --  
12 Colonial's looking at allowing up to R5 in its pipeline,  
13 even though it has jet, where it's got problem with the  
14 B.

15 And I know we're talking with Kinder Morgan,  
16 also, allowing R5 in some of Kinder Morgan's California  
17 pipelines.

18 So, there is a possibility that renewable diesel  
19 in the future could actually be put in at the pipeline  
20 injection point, or by the refinery, or by some --  
21 say -- help me out here -- the Port of Long Beach.

22 MR. BOWEN: Yeah.

23 MR. BRAUTIGAN: And avoid the need for some of  
24 the infrastructure. But I agree with you that the other  
25 problem is we just don't have any infrastructure for

1 biodiesel blending in California, yet we got a renewable  
2 fuel requirement for the diesel pool, so that's one of  
3 the reasons why we're saying it's hard to come up with  
4 something that you want to take to the bank and say this  
5 is how we're going to comply.

6 MR. BOWEN: Yeah, so I appreciate those  
7 comments, John. Taking them in reverse order, you know,  
8 Colonial you mentioned, they're also the pipeline  
9 company that's doing all the work on biodiesel, as well  
10 as renewable diesel in the pipeline. Kinder Morgan has  
11 also been doing a lot of work for both biodiesel and  
12 renewable diesel in the pipeline.

13 And I agree with you that the concerns about any  
14 contamination with jet, with the renewable diesel, no  
15 concerns because the cold flow properties are so  
16 impressive with the renewable diesel.

17 My comment about not knowing the compounds is  
18 more directed at the stage of development of renewable  
19 diesel. I mean, hydro-cracking is well known. But if  
20 you're using Neste's process, or UOP's process, or  
21 someone else's process, and then you're using a palm oil  
22 versus a tallow, versus a used cooking oil, versus a  
23 soybean oil, all of those things look different, at  
24 least based on the conversations that I've been having  
25 with UOP and others.

1           And it's not that they're bizarre, it's just  
2 that they're not yet well known, they're not yet  
3 standardized.

4           As you mentioned, ASTM is working on this and  
5 there are different opinions on how that's going to come  
6 out.

7           So, by and large I agree with you, just wanted  
8 to clarify that point.

9           Then coming to your point about your concern  
10 about RFS2, you're absolutely correct that the January  
11 and February volumes would send a signal that we're far  
12 short of the 800 million mandate.

13           A couple of reasons that is the case; one, you  
14 now, as you're well aware, there was the petroleum  
15 industry's lawsuit against the RFS, which only was  
16 resolved in December, so there was a lot of holding back  
17 of demand by obligated parties, and others, pending  
18 resolution of that lawsuit. So, it takes people several  
19 months to sort of ramp up to begin buying and  
20 incorporating biomass-based diesel, and biodiesel, in  
21 particular, into the fuel supply.

22           I think you'll see the March and April numbers  
23 is significantly higher than those January and February  
24 numbers.

25           I think you'll still see the run rate at a place

1 that would be disconcerting that we can make the 800  
2 million gallon per year mark without having a lot of  
3 catch up in the back half of the year.

4 We're having conversations with EPA about this  
5 and whether or not it makes sense to require obligated  
6 parties to report quarterly, rather than annually, so we  
7 can spread out demand more evenly throughout the year.

8 There is sufficient feedstock, there's  
9 sufficient production capability. And nationally, a lot  
10 of the country looks like California and there isn't  
11 good infrastructure. So, trying to get fuel into the  
12 southeast, into other areas of the country where we  
13 could have more volumes to more easily achieve the 800  
14 million gallon per year mark is more the issue, an  
15 infrastructure issue, than it is a fuel availability  
16 issue.

17 So, I do think we'll get reasonably close to 800  
18 million gallons. We may fall short but, you know, with  
19 those infrastructure investments coming in we should  
20 have no problem meeting the billion gallons next year  
21 and then going higher thereafter.

22 MR. BRAUTIGAN: My only comment was I think what  
23 you're going to find in the next several months, the  
24 only -- the components from the different renewable  
25 diesel processes are getting more and more defined.

1           It's basically is it a C14, 16, or 18, or 20  
2 hydrocarbon chain, but they know -- they know what's  
3 being produced by all those process from pilot runs, or  
4 in Neste's case, actual runs, they actually know -- they  
5 know the molecules.

6           MR. BOWEN: Yeah, and again, I want to make it  
7 clear, I'm a proponent of renewable diesel, it is a  
8 product that my company will almost certainly make when  
9 we think the time is right.

10           The point I just want to reiterate is the one  
11 you made, and I want to make sure the regulatory  
12 community is aware, ASTM and other key stakeholders  
13 haven't gotten to the point where there is a  
14 standardized definition of what is renewable diesel.

15           So, you're talking about hydro-treated renewable  
16 diesel, that's the one there's the most clarity.

17           There are Fischer-Tropsche renewable diesels,  
18 made from biomass. There's special bug renewable  
19 diesels, made from processes like amyris, which are  
20 using sugarcane and going through, you know, biological  
21 processes, all claiming the title of renewable diesel.

22           So, we need to figure out what is renewable  
23 diesel and how it's going to be dealt with.

24           Quite frankly, we would like to participate in  
25 all three of those types of renewable diesel, we think

1 they all have a role to play. We just need to be clear  
2 what we're talking about when we use the term renewable  
3 diesel.

4 MS. GREY: Gina Grey, from WSPA. Sorry, I'll  
5 make this quick, hopefully.

6 Eric, I think you very accurately said that in  
7 terms of B5 and the potential NOx impacts, that the  
8 National Biodiesel Board, and WSPA, and the Engine  
9 Manufacturers Association currently are in dialogue with  
10 ARB to talk about their supposition, at this point, that  
11 there is actually a NOx bump from AB5 level, which I  
12 think our three organizations at this point in time  
13 don't necessarily agree, we're looking at the science  
14 and the test data.

15 I think the point that I would probably disagree  
16 with is in terms of the characterization that if, in  
17 fact, there are issues there that we could just put in  
18 additives, or it can quickly be resolved.

19 And I think in our viewpoint, anyway, at this  
20 point in time that those mitigation options that have  
21 been offered up by ARB are not necessarily either the  
22 correct way to go, could be costly, could have other  
23 environmental impacts, et cetera.

24 So, I guess my one question here is in terms of  
25 the aquatic toxicity issue, which you also kind of went

1 through, that obviously was raised by ARB on December  
2 8<sup>th</sup>, when they had one of their contractors come forth  
3 and say that in their estimation there was some aquatic  
4 toxicity issues. And that's all part of the multi-media  
5 assessment that takes place in California.

6 He discussed the federal effort to look at those  
7 types of USDA issues, and everything else.

8 But just curious about how you foresee this all  
9 playing out in California, where we have our own process  
10 here, you know, the Environmental Quality Commission, or  
11 whatever it's called, that needs to look at all those  
12 types of issues, and whether or not this aquatic  
13 toxicity issue could be something that's of concern and  
14 that actually prevents biodiesel from coming into play  
15 in California, in the volumes needed, without  
16 exemptions, or other variances, or other things.

17 MR. BOWEN: Well, thank you, Gina, for the  
18 reiteration and clarification on some of those points  
19 and the question.

20 So, you're absolutely right, we all believe B5  
21 does not have any NOx increase that the ARB's just  
22 looking at the data the wrong way. And I definitely  
23 didn't want to leave anyone with the impression that  
24 there's an easy additive solution, it would be a  
25 headache.

1           I did also want to say that as you get into  
2 higher blends, where we acknowledge that with some  
3 biodiesels there is a NOx increase, we believe we will  
4 be able to find solutions for those fuels so they can  
5 participate in the marketplace, and/or just have certain  
6 types of biodiesels that are naturally high in cetane.

7           With regard to the aquatic toxicity, I have seen  
8 those reports. We're going through, under the review,  
9 trying to figure out exactly what that is. And we  
10 consider ourselves, and have from day one, to be an  
11 environmentally beneficial and friendly fuel,  
12 biodegradable, reduced air emissions across all  
13 regulated emissions, with the notable exception of NOx,  
14 as we've been talking about.

15           We have not yet had a chance to get through that  
16 and respond to ARB about what we think that means from  
17 multi-media. We certainly appreciate the effort that  
18 they're going through and think it's necessary and  
19 appropriate, so we'll address that when we can. Thank  
20 you.

21           VICE CHAIR BOYD: Thank you, Eric.

22           MR. WENG-GUTIERREZ: Okay, thank you, Eric, that  
23 was very good. It sounded like there was lots of  
24 conversation there, very good, but it did put us a  
25 little bit behind schedule, a little further behind

1 schedule. I thought we were doing great there for a  
2 little while and then all this conversation happened,  
3 which is great. We don't want to prevent that from  
4 happening, but we are then now a little bit over 30  
5 minutes behind schedule.

6 So, with that I'm just going to ask Gordon to  
7 come up and do his presentation, and he'll be MC'ing for  
8 the rest of the day.

9 MR. SCHREMP: Thank you, Jesse. Thank you,  
10 Malachi. Thank you, Eric, that was a lot of good  
11 information.

12 Are there any questions on my presentation? I'm  
13 just trying to speed things up here.

14 (Laughter)

15 MR. SCHREMP: Well, you guys have the slides.  
16 All right, I'll go through them rather quickly, I'll do  
17 my best.

18 VICE CHAIR BOYD: We know better than to ask you  
19 any questions, Gordon.

20 MR. SCHREMP: Yes. Infrastructure is very  
21 important. I think Eric allayed some of the issues,  
22 especially in the bulk terminals, on the diesel side,  
23 undoubtedly on the biodiesel renewable diesel side.

24 So, what we look at is more than just in  
25 California, because the whole system is distribution

1 terminals, over 50 of them, pipelines, interconnections,  
2 refineries, and all of this, but we are looking at a  
3 multi-state demand.

4 As Malachi mentioned this morning, we look at  
5 Arizona and Nevada because we provide nearly a hundred  
6 percent of Nevada's fuel and upwards of 50 percent of  
7 Arizona's fuel.

8 This is going to change a little bit and I'll  
9 talk about that in just a minute.

10 But, so we do demand forecasts for Nevada and  
11 Arizona, gas, and diesel, jet fuel. We also do  
12 renewable fuel forecast for those states, the same thing  
13 analogous to California, sort of a post-processing, we  
14 will look at RFS2 fair share compliance.

15 And we will further assume, as was mentioned  
16 earlier, Arizona will have an E10 cap over the forecast  
17 period, and I think we're considering doing the same for  
18 Nevada.

19 So, love to take people's comments on those  
20 assumptions.

21 So, demand forecast in Arizona and Nevada, why  
22 is that important? Demand goes up, more will be wanted  
23 to come out of California through the pipeline system.  
24 Demand goes down, the converse. So, that's important,  
25 that's why we look at it.

1           This is the interconnected system, just to  
2 demonstrate that Arizona gets fuel from the West Texas  
3 refineries and that volume, especially on the gasoline  
4 side of the ledger has increased over recent years, and  
5 the black lines are representative of petroleum product  
6 pipelines.

7           But it should be noted, no pipelines coming into  
8 California, it just leaves, because we're a net exporter  
9 over pipelines.

10           So, we look at an incremental approach, how much  
11 more or how much less barrels of petroleum products and  
12 renewable fuels? So, that's sort of how we do the  
13 demand forecast.

14           And we also look at, as I mentioned before,  
15 neighboring states and the fuel systems, including  
16 renewables. The new element is the Utah to Nevada  
17 pipeline, a petroleum product system that is near  
18 completion.

19           And this is the existing pipeline  
20 infrastructure. I think the map has -- I have to update  
21 this portion, there's only one line, petroleum products  
22 cannot be transported from -- essentially, they can no  
23 longer, I think, go this way, there's only one  
24 direction.

25           So, the products coming from the West Texas are

1 dropped off here and then can continue on to Phoenix and  
2 the west, but there's no ability to move from Phoenix  
3 the other way, except by trucking, of course, and the  
4 pipeline system up to Las Vegas.

5 So, the new pipeline is coming from the Utah  
6 refining complex all the way down into Northern --  
7 Northern Las Vegas.

8 So, this is expected now, I believe the update  
9 at their quarterly meeting, just recently, is later this  
10 summer it will be operational capability of the system.  
11 So, it's lagging just a little bit from the information  
12 in this slide.

13 The initial capacity is still thought to be  
14 about 30,000 barrels a day. Half of that will be  
15 delivered to a terminal in Utah that product is  
16 currently being trucked to. So, that supply already  
17 exists, now it's being a pipeline, a little bit safer  
18 means and less costly means of transportation.

19 The other portion, 15,000 barrels, that we're  
20 not quite sure how that will be split between gasoline  
21 and diesel, will go into Northern Las Vegas. Now,  
22 that's a modest amount, but it will affect our outlook  
23 for the neighboring state. And there is a potential to  
24 expand in the future on the pipeline's capacity.

25 However, the limiting factor is likely adequate

1 excess barrels available from the starting point in that  
2 system and that's the Utah refining complex, as well as  
3 the ability to get products into that system. At times  
4 that's a market that can be short on supply, so we're  
5 not assuming that it's going to be 50, 60, 80 thousand  
6 barrels of spare supply to go into Northern Las Vegas.

7 Marine oil terminal engineering and maintenance  
8 standards, or we love to use acronyms, MOTEMS. This is  
9 very important, this regulation as part of the Business  
10 Code is proceeding. All of the assessments and safety  
11 Is have been completed on the highest risk, marine oil  
12 terminals, and which are basically all of the ones that  
13 are utilized in California, in Northern and Southern  
14 California.

15 And so now it's in the discussion phase, the  
16 most important level about, okay, when are these  
17 upgrades going to begin?

18 And in Southern California, especially, the  
19 tenants of all the terminals are under lease agreements,  
20 they don't actually own the property, and that is a  
21 different dynamic from Northern California.

22 So, what we're seeing is that those with lease  
23 agreements, that are nearing expiration are, you know,  
24 in discussion about will they move forward, will they be  
25 renewed? If they are, co-paying, co-sharing the cost,

1 the Port doesn't carry all of the bill or all of the  
2 bill. So, these are underway and an important  
3 consideration because the Port will actually look to the  
4 IEPR forecast for whether or not all of these facilities  
5 need to be upgraded, this is especially the case in  
6 Southern California. So, they're paying close attention  
7 to our forecast for crude oil imports, as well as  
8 transportation and renewables.

9           Now, what may be missing from all that dynamic  
10 is how spare capacity may be viewed by the people  
11 involved in these negotiations. And whereas we don't  
12 look at a marine terminal as a steady state operation,  
13 like a base load, you know, electricity producer, we  
14 look at that as having to need some spare flux in there  
15 because of the indeterminate nature of the arrival of  
16 marine -- of marine deliveries. From time to time it's  
17 not as precise as other conveyance means.

18           As well as the sort of intermittent need to  
19 temporarily move more product through a particular oil  
20 terminal because of an unplanned refinery IRG.

21           And a final point of why just looking at spare  
22 capacity may not be the correct dynamic to view these  
23 terminals is the potential closure of a California  
24 refinery that, you know, two years ago, four or six  
25 years ago was sort of unheard of in our sort of thinking

1 ahead, but now is a much more, I think, realistic  
2 scenario based primarily because of a significant  
3 decline in gasoline that we forecasted two years ago,  
4 and as well as this go round, we anticipate.

5           So, we're looking at capacity, we want input  
6 from stakeholders on what the outlook is for these  
7 projects and what the needs are.

8           And so, you know, once again we're here, we've a  
9 process, we want input, we want input of the docket, to  
10 be better educated on where we're going. But we do  
11 recognize that the stakeholders do wait for us to put  
12 out a forecast, and the draft report to comment on. But  
13 there is probably some valuable information, they could  
14 provide insights to us prior to that -- that time.

15           So, distribution terminals, ethanol and  
16 biodiesel are delivered via primarily tanker truck. I  
17 know Eric mentioned we'd like to have rail. I think,  
18 yes, so would they. A lot of those rail spurs have been  
19 gobbled up, development has encroached upon a lot of  
20 these distribution terminals, so that's pretty  
21 problematic at this point.

22           So, it's biodiesel, it's drop-in hydrocarbons as  
23 Eric mentioned. Renewable diesel imports via rail car,  
24 how do you get them? Is it transloaded to tanker  
25 trucks? You know, what are these issues, including

1 renewable and natural gas, and that was discussed  
2 earlier this morning, and that infrastructure. Getting  
3 into that infrastructure, what are some of these  
4 limitations and challenges that we need to be aware of  
5 and to see what -- you know, how some of these barriers  
6 can be overcome.

7           So, those are my slides and somewhat brief for  
8 me. Any comments?

9           VICE CHAIR BOYD: Thank you, Gordon, I wouldn't  
10 dare.

11           MR. SCHREMP: Okay.

12           All right, I'll hand the microphone off to Matt  
13 Tobin, of Kinder Morgan.

14           MR. TOBIN: Thank you, Commissioners. And thank  
15 you, Gordon, I appreciate the opportunity to come and  
16 speak with you today.

17           I'm actually speaking on behalf of Kinder Morgan  
18 Terminals. Pipeline infrastructure obviously here, in  
19 California, is the major asset base, but we do a little  
20 bit of business in a different way across the U.S. I'll  
21 talk a little bit about the market and talk a little bit  
22 about what Kinder Morgan is doing in a general sense and  
23 what we're doing here in the State of California.

24           The ethanol industry over the last number of  
25 years, especially from a distribution infrastructure

1 perspective has really matured. There's been a lot of  
2 work, a lot of capital spent on various areas of  
3 development across the U.S. to support the RFS2, to  
4 support what generally is a ten percent mandate across  
5 the U.S.

6 So, last year there was sort of a 12.5 billion  
7 gallon consumption level for ethanol within the U.S. as  
8 a blend component.

9 This year we'll probably be closer to 13.3, when  
10 it's all said and done. Running about 9.4 percent right  
11 now, the gasoline pool is ethanol, so it's inching up to  
12 toward what they call the blend wall, right around the  
13 14 billion gallon level.

14 From a terminal perspective, because we're  
15 heavily engaged in the distribution of gasoline  
16 throughout the U.S., we spent a ton of time and effort  
17 on trying to get this right for our network. A lot of  
18 effort in the New York Harbor, all the way down into  
19 Florida, the Chicago market, Houston Gulf, and in  
20 California, in particular. We probably have 70 plus  
21 terminals right now that are handling ethanol in some  
22 form or fashion across the U.S.

23 And that's, obviously, necessitate a large  
24 investment in our tank infrastructure. We put in place  
25 right now, just over the last couple of years, nearly

1 five million barrels of storage capability across the  
2 U.S. All of that has been kind of incremental, year  
3 over year as we go, just trying to keep up with our  
4 customers' demands on making sure the product is where  
5 it needs to be at the right time.

6 And it has a wide variety of capabilities across  
7 the system as well, we just have to keep up.

8 California was a little bit unusual in that  
9 there was a huge amount of demand and, actually, the  
10 first big ethanol unit train operation was developed  
11 here around the 2002-2003 time frame in Lomita, what we  
12 call the Lomita rail terminal, in the L.A. Basin.

13 And what that does is it's hooked up to Shell  
14 Carson, and trains come in either 96 or 112 car, they're  
15 unloaded into the pipe and sent up in the storage, and  
16 then distributed out through the Carson rack.

17 That model was emulated pretty much across the  
18 country and between the New York Harbor, our couple of  
19 big developments out there, or course, in the Gulf,  
20 Chicago area, that has been the way that -- has been the  
21 way to go.

22 Within California other developments of that  
23 nature are difficult. It's very difficult to permit,  
24 it's very difficult to get the storage space to be able  
25 to do this, it's very difficult to get the railroads to

1 cooperate, et cetera, et cetera.

2 That being said, we have essentially five unit  
3 train facilities here in California. One, as I  
4 mentioned, in Lomita. The other in Colton, California,  
5 which is just out around Riverside area. That's not a  
6 true connected pipeline operation, yet, but it's got  
7 unit train transload capability.

8 We run the same kind of facility up in Richmond  
9 that was put in place in March of last year. They're  
10 able to take a hundred-car trains in there and  
11 distribute it out via truck.

12 Selby is really more mature, it's able to have  
13 some marine capability there.

14 And Stockton, depending on what happens with  
15 Pacific Ethanol, can be in the storage and distribution  
16 business. Right now it's a very difficult situation  
17 with the price of corn to be -- to be in the destination  
18 production infrastructure business, and they're working  
19 through that right now.

20 I should mention this, Gordon asked me to talk a  
21 little bit about assets outside of the State of  
22 California that could have an impact on how product is  
23 distributed here.

24 We have, over the last number of years, sought  
25 to develop a facility in the Houston area. This one was

1 put up just in April of this year. We have the ability  
2 to take hundred-car trains and to put it into storage,  
3 and generally for the Houston market, the greater Texas  
4 market.

5 But what really drove this opportunity was the  
6 fact that we had a big spot on which to land trains and  
7 an even bigger spot on which to land product.

8 If you look over on the left-hand side of the  
9 screen, that's our Pasadena facility, between Pasadena  
10 and Galena Park we've got about 25 million barrels of  
11 storage, and Deer Park has about 1,200 rail car spots.

12 We connected the two via pipe, with the idea,  
13 potentially, of using this as a spring board to satisfy  
14 LCSF demand. The reason being rail infrastructure here  
15 is such that you can take product, we can actually load  
16 trains, our Brazilian product, that would find their way  
17 into the Houston market and then send them out to the  
18 West Coast.

19 And the reason being is that the whole idea,  
20 there's been a lot of talk about Brazilian product, and  
21 Brazilian product coming into the States, and it's had a  
22 generation, I guess, a couple of C changes in it.

23 Brazil was generally the source of the world's ethanol  
24 for quite some time. Now, because of their own domestic  
25 demand, it's very difficult to find the right amount of

1 product to send out.

2           The California demand, more or less on an annual  
3 basis, 1.5 billion gallons. The total exports out of  
4 Brazil are something less than 900 million gallons, and  
5 in 2009, much less last year. It's to the point right  
6 now where Brazil is so short ethanol that we've taken on  
7 the -- through the Port of Houston, sending ASTM grade  
8 down to Brazil as imports for Brazil because they're  
9 short of their product.

10           I mean, over the last number of the years,  
11 they're getting to the point right now, I guess by 2012  
12 UNICA says that they'll have 50 percent of their  
13 automobile fleet will be fully flex fuel capable. And  
14 they'll have either an E25 blend or an E100 blend.

15           Last year, because they were short ethanol and  
16 there was a little bit of a drought, they knocked it  
17 down to E20 and they actually had to import gasoline to  
18 make up the difference.

19           Now, because of the price of gasoline worldwide,  
20 they've elected to import their ethanol to be able to  
21 make grade.

22           They have some very, some difficult specs for a  
23 lot of U.S. terminals because it has to be DSP  
24 compliant, it has to go out as undenature. But in this  
25 case they were so short they said we'd take ASDM grade,

1 flat out.

2           So, a very interesting situation and it's a  
3 little bit problematic, I guess, from a distribution  
4 stand point. Even in the best of circumstances, if you  
5 could take Brazilian product out of, let's say, Santos  
6 and move it up through the canal, and move it up into  
7 the West Coast of the U.S., you're looking at vessel  
8 sizes approaching 300,000 barrels and that kind of lands  
9 with a thud on the West Coast. It has to hit -- it  
10 isn't that you would be short terminaling capacity  
11 necessarily, per se, it's just that you have to have the  
12 space and the capability to be able to take in 300,000  
13 barrels at a time, which is about what those vessel  
14 sizes are.

15           So, invariably, what would happen then is that  
16 vessel will have to multi-port its way up across the  
17 West Coast and have those economics work, which is it's  
18 a little tricky.

19           Our thought in using Houston as a spring board  
20 is to go to the Brazilians, which we've done, and said,  
21 look, it's a five-day milk run up to the Gulf Coast,  
22 send product up there, you can put product in storage  
23 with Kinder Morgan. We can take that product, if we  
24 need to segregate it, if we don't -- I think we don't,  
25 has long as -- we have to demonstrate a pathway,

1 according to what CARB is telling us, and we can send  
2 product out to the West Coast, use all the existing  
3 infrastructure, and have trains out of Houston to  
4 Lomita, Northern California in four to five days. That  
5 takes it out of -- that takes the pressure off of the  
6 supply chain a little bit.

7           But in the best case coming out of Houston, I  
8 mean we could probably do a couple of trains a month,  
9 four, five, six, eight, maybe. You're looking at demand  
10 here somewhere in excess near 100,000 barrels a day of  
11 ethanol coming in. So, it's a huge challenge,  
12 logistically, to make all this happen.

13           Just a couple -- I told Gordon I'd give him a  
14 couple of words from our products pipeline side, on kind  
15 of where we're seeing the pipeline issues now, and  
16 especially with regards to MOTEMS.

17           We are being -- we've had our lease non-renewed  
18 in the Port of Los Angeles or the Port of Long Beach, so  
19 we're going to be leaving there this year. We probably  
20 would have had a MOTEMS obligation, but as a result of  
21 our leaving it no longer exists. We're looking for  
22 other alternatives right now.

23           UNEV, it's a little tricky. I think Gordon was  
24 spot on, it's hard to tell right now, but there doesn't  
25 appear to be a huge over-supply of product in the Salt

1 Lake City market that would need to find its way down to  
2 the greater Vegas market. It's hard to tell right now.

3           The economics we that we saw in coming into the  
4 pipeline, it led us to believe that the refining  
5 economics were really driving this. This is something  
6 we don't do because we're not in the refining business,  
7 necessarily. But there may be other reasons for making  
8 that -- this go.

9           We don't see a huge amount of product that would  
10 have otherwise not gone into Vegas via the CalNev line  
11 not going now. But it remains to be seen. As Gordon  
12 said, I think they're due to be up the third quarter of  
13 this year. They have a couple of terminals I think  
14 already up and going, so we'll see how that works out.

15           One of the other things he asked us to comment  
16 on was the Longhorn pipeline. There is talk, now, that  
17 Magellan, who bought Longhorn from Flying J would elect  
18 to reverse the direction of that line and send crude  
19 product out of the Permian Basis back in the Houston  
20 area. And, traditionally, Longhorn has always run  
21 refined products out, made its way to El Paso, and El  
22 Paso has then taken it on to the west.

23           I'll tell you, it's very difficult right now to  
24 imagine them not wanting to reverse it. The crude oil  
25 demand in Permian Basis, in particular, at, you know,

1 \$90, \$100 crude really favors them pushing product into  
2 the Houston area.

3           Likewise, there's been a substantial amount of  
4 development in the Eagle Ford Shale that will allow for  
5 crude to make its way, again, in Houston refineries, at  
6 really attractive numbers.

7           So, within our shop and I know within a variety  
8 of others, midstream players, like Kinder Morgan  
9 terminals, we're looking at crude really hard right now,  
10 and infrastructure around the -- development of  
11 infrastructure around crude is almost a mirror image of  
12 what happened with ethanol a couple of years ago. You  
13 could see terminals here and we've actually been  
14 approach to look at terminal developments for crude oil  
15 coming into the State from various places, like North  
16 Dakota, or others. So, very interesting circumstance.

17           My contact information is up here. And Jim  
18 Kehlet really runs the pipeline side, if you have any  
19 questions on the pipeline side, he's over in Orange,  
20 California.

21           Questions?

22           VICE CHAIR BOYD: Thank you. Any questions?  
23 Gordon? Anyone? All right, thank you very much.

24           Oh, Gordon, you do have a question, I was  
25 unclear.

1           MR. SCHREMP: Well, thank you, Matt, you kind of  
2 left us hanging there. It's like Paul Harvey, I'd like  
3 to know the rest of the story.

4           You said your operational marine terminal in  
5 Southern California which is, I understand, connected to  
6 your Carson Tank Farm, you have lots of clients in  
7 there. You're looking for other alternatives and,  
8 clearly, that is code for pipeline connection to the  
9 water so you can still utilize or your customers can  
10 still utilize those tanks.

11           So, my question to you is that for the sake of  
12 argument, yeah, you will keep pursuing this and  
13 ultimately be successful, would that increase or  
14 decrease the through-put capacity of Southern California  
15 ports, losing your terminal?

16           MR. TOBIN: That port, it did some very  
17 specialized things, and it did some very good California  
18 things and did some expert as well.

19           And the answer is right now I don't think we're  
20 sure. I wish there were a lot of very easy things that  
21 we could look at, but everything that we've looked at is  
22 really expensive.

23           That being said, I know my guys in Orange are  
24 working very hard to put ourselves in a position to be  
25 able to do something beyond 2012. Yeah, we're going to

1 have to look at different ways of doing business if we  
2 don't have an outlet there.

3 MR. SCHREMP: Thank you very much, Matt.

4 And I'll hand the microphone off to Jim  
5 Iacoponi, from Propel. Jim.

6 MR. IACOPONI: Thanks. Thank you, Gordon,  
7 Commissioner. Good afternoon, everybody.

8 A lot of the conversation's been quite at the  
9 macro level here. I'm going to do two things, I think,  
10 differently. First is I'm going to bring it down a  
11 little bit to the micro level and share some experience  
12 that we've had recently, as much about a product  
13 opportunity for the State of California, but also as a  
14 little vignette about our experiences in working our way  
15 through the State.

16 I'm sure no new learnings for most of the people  
17 present, but it just sort of may bring to home  
18 opportunities.

19 And the second thing is I will have brief  
20 comments so, hopefully, that will help get things a bit  
21 back on track.

22 One of the things that my team does, we're the  
23 operations folks for Propel, we do is look for  
24 opportunities to bring lower carbon and renewable fuels  
25 both into our own system, into the State and, also, at

1 the end of the day we're really in the business of  
2 matching product fuel opportunities with customers.

3           And last -- last fall we were approached by a  
4 couple of producers with the potential to introduce into  
5 the State of California a new product, renewable diesel,  
6 now being produced at commercial scale. So, clearly, we  
7 wanted to take a look at, well, what is this? Is this  
8 anything that would be allowed by the State? Is this  
9 anything that would have customer interest?

10           And I think Eric did a great job of framing up  
11 what the market realities are. Transporting fuel is  
12 expensive when it's not produced here, locally, and the  
13 cost of handling, actually, puts it -- puts it in a  
14 place where customers have to be quite interested in the  
15 environmental benefits to consider it as a fuel and a  
16 replacement for either diesel or for biodiesel.

17           I think when presented with the specs that are  
18 on here we were really surprised and also, I would say,  
19 delighted at the opportunity for the potential  
20 environmental impact that such a fuel could bring to  
21 both the customers that we were speaking to, but also to  
22 the State of California, and particularly in the non-  
23 attainment areas.

24           You know, I won't go through and read them all,  
25 but I think that the upshot is that when you look at a

1 product spec for a real product being made today  
2 available in commercial quantities you say, okay, number  
3 one you get huge environmental benefit and you can get  
4 it immediately.

5 I think the second is that for the customer, and  
6 certainly at the customer level, they don't need new  
7 equipment. They, at the customer level, don't need any  
8 particular storage changes. They don't need to be  
9 thinking about putting in large tanks, pressure tanks,  
10 they don't need to be overhauling diesel systems, they  
11 don't need to be thinking about any of the maintenance  
12 changes for replacing, converting to, say, a compressed  
13 natural gas, and they can get benefits immediately, and  
14 they can bring their region benefits immediately.

15 And so with that thinking going out in the  
16 market in fact, despite some of the cost challenges, we  
17 found customers that said, yes, this would be a  
18 phenomenal opportunity for us, can you get the State to  
19 agree.

20 And we said, you know what, our job is to  
21 actually bring you and this opportunity together and we  
22 are happy to take on leadership in working with the  
23 State.

24 I think that where we are today is at the higher  
25 level, so renewable diesel and, again, the point is that

1 renewable diesel has multiple flavors, it has multiple  
2 definitions. What is approved by the U.S. EPA? At what  
3 level, is it a hundred percent blend, is it an R20  
4 blend?

5           Currently, this particular product could be used  
6 and is permitted at the U.S. EPA level at an R20 level.  
7 And there is a pathway to get it through to an R100  
8 level. I think that's good news for both the customers  
9 who are interested and, clearly, the environmental --  
10 the environmental benefits.

11           When we work through the different hurdles what  
12 we find is that actually the lack of definition of what  
13 this product is runs into the familiar can it be stored  
14 underground in the State of California?

15           When we look at -- when we look at its  
16 specifications we've got a sample, we've had it tested a  
17 number of times. You line it up next to diesel fuel,  
18 the people that we speak to, and we've had, I would  
19 emphasize, within the Energy Commission, the Water  
20 Board, and the ARB, just phenomenal support by staff.

21           When we take these specifications to staff they  
22 say, we can't tell the difference. But it doesn't meet  
23 the regulation as it's known today and so one runs into  
24 a bit of a hurdle.

25           I think it was also very well brought out,

1 earlier, that at the bulk level the bottom line is to  
2 make fuel economic for customers. While they may be  
3 willing to pay some premium for environmental benefit,  
4 to meet corporate goals, to be -- to also state and  
5 local governments to help meet local attainment goals,  
6 there may be some premium that is affordable, but that  
7 is not affordable without sufficient quantities being  
8 moved, being stored, being transloaded to help bring  
9 down those infrastructure costs.

10           And so, current hurdles to real successful  
11 implementation, in addition to the first two, really lie  
12 in this notion of what bulk handling and storage  
13 infrastructure will be available and how might fuels,  
14 such as this, take advantage of it?

15           And I think then, at the last, with anything new  
16 there isn't a lot of public information that supports  
17 the magnitude of the environmental benefits that one  
18 would expect to get from the product, such as this when  
19 you look at the specifications.

20           And, you know, so in this State it strikes us  
21 that this is a real opportunity for a public/private  
22 partnership to conduct testing, to really understand the  
23 nature of a fuel such as this.

24           Which really then leads me to this slide, which  
25 is what I wanted to share. The questions that I've put

1 on this page really describe a journey of about nine  
2 months. And you go down a path, and then you go down  
3 the next path, and then you go down the next path. To  
4 encourage a producer to make an investment, to encourage  
5 product investment in product storage and handling along  
6 the way and, actually, at the end of the day to  
7 encourage customers to want to sign up for a new fuel,  
8 all of these have to be gone through.

9           And, therefore, and it's not -- it's not just  
10 answering the questions, what we need is the confidence,  
11 through written communication that can go back to  
12 producers, to handlers, to customers to say there is a  
13 fuel, we can actually take your demand and match it with  
14 your supply, and bring together change for the better  
15 for the State. Hence, the last line "can we get this in  
16 writing?" Which is -- which is always interesting but,  
17 again, we've made some good progress.

18           How can you help? I think, very simply,  
19 consider whether or not there couldn't be a single point  
20 of coordination amongst the different State level  
21 agencies to help clear implementation hurdles for new  
22 fuels. We've had conversations not just in the diesel  
23 space, but also in the renewable gasoline space, and  
24 everyone within the State and outside the State asked  
25 the same questions; can I sell this to anyone and what

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1 are the hurdles of getting there?

2           And so, getting help with that would be -- would  
3 be great.

4           Secondly, I believe, Propel believes that a  
5 coalition of agencies to understand what would a  
6 coordinated set of tests look like for air, emissions,  
7 and also to meet some of the other questions that might  
8 come up with regard to energy efficiency.

9           Can there be, again, a single point that says  
10 this is an appropriate testing program and then help  
11 with companies looking to put their products into this  
12 testing program.

13           And I think the last is just recognizing that at  
14 the end of the day the pace at which programs move,  
15 particularly the pace at which test programs, or fuel  
16 approval programs move is really what allows a market to  
17 be developed.

18           And what California wants is to develop the  
19 market for renewable fuels. Sometimes they might be  
20 segregated products, sometimes they might have  
21 particular NISH applications to encourage producers to  
22 make the investment, to go through the process on  
23 permitting if there's a way to stimulate demand in  
24 advance through small, one-off projects and, again,  
25 small companies such as Propel can certainly work in

1 this space, that kind of support, moving at pace with  
2 your continued interest in supporting storage and  
3 handling investment would be great. Thanks. And those  
4 are my comments.

5 VICE CHAIR BOYD: Thank you. I guess I showed  
6 my hand of interest earlier in the day, so you've posed  
7 a lot of interesting questions you're to pursue.

8 Any questions from folks?

9 Gordon, did you rise for a question or are you  
10 just --

11 MR. SCHREMP: Thank you.

12 VICE CHAIR BOYD: All right, thank you very  
13 much.

14 MR. IACOPONI: Thank you very much.

15 MR. SCHREMP: Thank you, Jim.

16 Chuck White, from Waste Management, is our next  
17 guest speaker.

18 MR. WHITE: Good afternoon. I can get started  
19 while we're getting this set up, as long as I don't have  
20 to go on too far without my Power Point slides, which  
21 I'm always a little bit having to rely on.

22 I'm the Director of Regulatory Affairs for Waste  
23 Management in California, and Western U.S. I have to  
24 say, it feels as though I'm a little bit out of my  
25 league with all these experts in the field of fuel and

1 energy. I'm a waste guy, so I hope you'll bear with me  
2 if I don't -- if I demonstrate my ignorance.

3 But I really appreciate the opportunity to be  
4 here to talk about some of the things that Waste  
5 Management is doing in developing fuel platforms to  
6 serve our needs.

7 And starting off on this chart, of where I've  
8 titled this slide "Closing the Loop on Transportation  
9 Fuels" and I hope that will become clear why I chose  
10 that title, when I get through this brief presentation.

11 Now, you can see the five pictures up there kind  
12 of portray what Waste Management is. We're a 12 and a  
13 half billion dollar revenue per year company. We have  
14 about 45,000 employees.

15 Our principle, where you see us in activities,  
16 is collection and transfer of waste and recyclables. We  
17 have 20 million customers in North America. We have 367  
18 hauling companies around the United States, and we have  
19 19,000 heavy-duty trucks in North America.

20 So, we basically are a transportation company  
21 from the collection and transfer.

22 We're also a disposal company. We have 273  
23 landfills, and those landfills are basically big,  
24 anaerobic digesters that generate a lot of methane,  
25 which is both a good thing and also a bad thing,

1 depending on how that's managed.

2           We're the world's -- we're North America's  
3 largest company of collecting recyclable materials and  
4 we're also getting to view ourselves more and more as a  
5 renewable energy company. I didn't used to come over to  
6 the Energy Commission very much about three or four  
7 years ago, and now I find myself over here almost weekly  
8 on a variety of issues that are directly related to the  
9 services we provide.

10           Here's a picture of a map of our 367 hauling  
11 districts in North America with our 19,000 heavy-duty  
12 fleet. Each dot represents anywhere from five to over a  
13 hundred heavy-duty vehicles. The average fleet size of  
14 each of those dots is 50 heavy-duty vehicles.

15           Nationwide we only have about -- well, this says  
16 a thousand, we have about 1,200 natural gas trucks,  
17 about five or six percent of our total heavy-duty fleet,  
18 but that's changing rapidly.

19           In the west group, where I mostly do most of my  
20 work, we've got 5,000 heavy-duty vehicles in these  
21 states. We're focusing, really, in California, a little  
22 bit in the Seattle area. We're generally converting our  
23 fleets over to natural gas, both CNG and LNG. We have  
24 five CNG fueling facilities now, we have ten that are in  
25 the development process, handling about 500 trucks in

1 the west. We have nine bio-LNG facilities, where we  
2 bring both natural, fossil-LNG and bio-LNG that we  
3 produce at our Altamont bio-LNG facility near Altamont  
4 Pass, in Northern California. That produces about  
5 19,000 gallons a day that we distribute to these nine  
6 bio-LNG facilities. And we're in the process of  
7 developing five LCNG facilities, so we can both use  
8 liquefied and CNG for fueling our trucks.

9 Waste Management is really in the process of  
10 converting our entire fleet. We're ahead of the game in  
11 California, about 31 percent of our fleet of 3,200  
12 trucks is LNG or CNG, and we're doing everything we can  
13 to convert our fleet to natural gas as fast as we can.

14 Our goal is that 80 percent of our new heavy-  
15 duty vehicle purchases will be either LNG or CNG  
16 platform trucks. We would do even more, but it -- and I  
17 say it's a goal because we still have the fueling  
18 infrastructure problem. Fueling infrastructure is the  
19 biggest problem facing us because these fueling  
20 facilities cost anywhere from two to three million  
21 dollars for the fleet size that we're talking about, in  
22 addition to providing public access where that's  
23 possible.

24 So, it's a huge cost and that is the big barrier  
25 in doing even a faster conversion of our fleet.

1           And looking at the carbon intensity of  
2 alternative fuels, one of the many reasons we've chosen  
3 to migrate to natural gas or renewable natural gas is  
4 it's a two-step process. The first step is converting  
5 to fossil natural gas, but the second step is once you  
6 get onto the natural gas platform, it's easy just to  
7 convert over to renewable natural gas as your fuel.

8           As you can see from this bar chart, the bars on  
9 the left are ultra-low diesel, following by B20 and  
10 B100. You can get the same carbon reduction as B20,  
11 biodiesel 20, simply converting over to fossil natural  
12 gas and fossil -- either fossil CNG or fossil LNG. But  
13 if you make the next step to biogas, you can get as much  
14 as a 90 or more percent reduction in your carbon  
15 intensity.

16           Where do you find biogas? Well, believe me,  
17 it's everywhere. It's available at landfills, it's  
18 anyplace where anaerobic digestions going of animal  
19 food, sewage, and crop wastes. Waste Management is  
20 focusing on landfills because, why, we have a lot of  
21 landfills, and there's a lot of potential for  
22 development of unused, un-beneficially used landfill gas  
23 to create energy and biomethane.

24           The next area we're looking at is the unused  
25 capacity of sewage treatment plants, where they have

1 anaerobic digesters, where we can divert food waste from  
2 landfills. There's a big effort in California to focus  
3 on food waste diversion. We have a proprietary process  
4 to process food waste, to separate any plastics, and  
5 glass, and metals in that and basically put a product  
6 that can then go right into an anaerobic digest, or a  
7 POTW. They're already built, they're already  
8 constructed, the capital investment is already there,  
9 they just need to be retrofitted with something to  
10 capture the gas to turn it into a fuel that could be  
11 used to fuel our trucks.

12           So, we're really looking at a wide variety of  
13 different ways that we can take advantage of the  
14 anaerobic digestion process that's going on all around  
15 us.

16           Very low greenhouse gas emissions, just the  
17 lowest that's available in California, DOE estimates  
18 that about 10 billion gasoline gallon equivalents per  
19 year are available to basically displace 90 million  
20 light-duty vehicle equivalents from the roads and  
21 throughout North America.

22           Natural gas is really the high -- is the low-  
23 hanging fruit. It's from the anaerobic decomposition of  
24 organic waste in a landfill. Gas is about one-half  
25 percent methane -- one-half methane, one-half carbon

1 dioxide, with some nitrogen and oxygen, and additional  
2 impurities that need to be refined out.

3           As it comes out of the landfill it's a medium  
4 BTU gas, we've typically used it to bear in engines and  
5 turbines to generate electricity. We're running up  
6 against problems on air emission standards throughout  
7 California and so that was one of the many reasons why  
8 we decided to look and explore ways to generate fuels,  
9 instead of electricity.

10           Here's an LCF lifecycle assessment of landfill  
11 gas to LNG, for example. If you take a look at the  
12 landfill, you collect the gas, it typically would go up  
13 into a flare. It's required to be flared, required to  
14 be burned, you just simply can't discharge it to the  
15 atmosphere.

16           There may be some fugitive emissions, but if we  
17 can divert the gas away from the flare into a fuel  
18 production, into transportation and fueling, and then  
19 the pump to wheels at the end, there maybe are some  
20 emissions along the way.

21           But in the case of fuel production, if we can  
22 use the energy for the fuel production at their landfill  
23 to be generated by biogas, then we're also further  
24 lowering the carbon intensity.

25           And so this is basically you're displacing gas

1 that would have otherwise gone up into a flare, you're  
2 redirecting it into a fuel and it displaces fossil fuels  
3 with -- to a very low carbon intensity.

4 Here are the carbon intensities I borrowed from  
5 the LCSF, they're the most recent, some of the most  
6 recent numbers that are up there. You've got the fuel  
7 type on the left, direct well to wheel emissions,  
8 indirect emissions, total emissions, then the percent of  
9 emissions relative to diesel.

10 And the red is gasoline and diesel and you can  
11 see that's the big kind of the baseline we're trying to  
12 provide a reduction from through the low-carbon fuel  
13 standard.

14 Ethanol, all the ethanol ones that are currently  
15 posted are all crop-based ethanol. You can get down,  
16 even some of them, like Midwestern coal is a higher  
17 carbon intensity than diesel or gasoline. You can have  
18 some reduction in ethanol.

19 You can even get further reduction in ethanol if  
20 it's waste-based ethanol. There aren't any pathways for  
21 that right now in the low-carbon fuel standard.

22 Getting down to lighter color yellow you get the  
23 biodiesel and you only really get the real reduction in  
24 carbon intensity from biodiesel if it's a waste-based  
25 biodiesel, like waste cooking oils, waste corn oil,

1 waste tallow.

2           The green at the bottom is where we want to end  
3 up, is making the transition through step one to CNG or,  
4 potentially, LNG, from fossil sources, about a 70  
5 percent reduction -- excuse me, a 30 percent reduction  
6 in carbon intensity, but to really make this next step  
7 into renewable CNG, renewable LNG, with even -- even  
8 much greater reductions.

9           And these default total emissions levels that  
10 are produced by CARB, are the low-carbon fuel standard,  
11 are based on the assumption that the electricity used to  
12 run the power plant, run the refinery at the landfill is  
13 from the grid.

14           As I indicated previously, we'd like to make  
15 sure that we provide electricity that is a biogenic  
16 source of landfill gas, for example, and you can get  
17 even a further carbon reduction down to maybe five  
18 percent in the range of diesel.

19           We think we can even do better than that by, and  
20 this chart tries to portray that. It's kind of similar  
21 to the chart you saw before, but rather than using  
22 landfill gas, we would intercept the waste before it  
23 goes into the landfill and divert it over to a  
24 conversion technology type of facility and produce a  
25 gas, either a methane, or a syngas that would go into

1 fuel production, to transportation and then, finally,  
2 the pump to wheels process.

3           The benefit of actually intercepting the waste  
4 before it goes to the landfill is you might get a  
5 further carbon reduction by reducing fugitive methane  
6 emissions from the landfill because you're intercepting  
7 the waste. Instead of going to the landfill and  
8 generating gas that's collected in a flare, but also  
9 generating gas that's fugitively emitted, you avoid the  
10 fugitive emissions.

11           And we're interested in seeing if CARB will take  
12 a -- will recognize this as a legitimate source of  
13 carbon reduction in those kind of fuels that are based  
14 on waste that are diverted from landfills, and going  
15 into a conversion technology process.

16           What you can actually end up here is a fuel with  
17 a carbon intensity that's less than zero. You can -- if  
18 you start off with 95 grams per mega joule, you may get  
19 120 grams per mega joule reduction, so you're actually  
20 in a negative territory in your overall carbon  
21 intensity.

22           You're not going to find any fuel that has a  
23 lower carbon intensity than a waste-based fuel that's  
24 based on diversion of that waste from a landfill.

25           Waste Management has partnered with Linde and

1 the Gas Technology Institute to build the world's first  
2 and largest commercial landfill gas to LNG plant. It's  
3 a \$15.5 million plant, it's not cheap. It's 13,000  
4 gallons of biodiesel per day, about five percent the  
5 carbon intensity of diesel.

6 We have a second plant planned for Southern  
7 California, with the assistance of this Energy  
8 Commission. The first plant at Altamont couldn't have  
9 gone forward without about \$2 million in government  
10 grant funding from the Waste Board, CARB, the Energy  
11 Commission, and the South Coast Air Quality Management  
12 District. It's the largest effort to introduce on-site  
13 liquefaction for landfill gas in North America.

14 Here's the design of the facility. Are there  
15 are any questions about how this process works?

16 (Laughter)

17 MR. WHITE: Well, if there are, you're going to  
18 have to talk to the Linde Group for details because they  
19 really were the experts that brought on the technology  
20 to make this happen. The bottom line, it's complicated.

21 Some of the challenges we had were aligning  
22 these multiple-unit processes, there's about five or six  
23 unit processes that are all combined together, in  
24 tandem, to provide the overall treatment and it  
25 required, really robust design and commissioning to go

1 from 50 percent methane to a final product that has 96  
2 plus percent methane.

3 Having to reduce CO2 from 50 percent to 50 parts  
4 per million required a really unique polishing process  
5 using a molecular absorbent.

6 There's a variety of non-methane organic  
7 compound species and amounts and, really, the benefit of  
8 the multi-stage design that Linde put together was  
9 really making sure if you don't catch it in one process,  
10 you can catch it in the second process, you can catch it  
11 in the third process.

12 So, we really feel comfortable that this really  
13 can provide a high performance, high level, high purity  
14 level of purified -- well, renewable natural gas that we  
15 then, in turn, liquefy. And this is the first case  
16 where the Gas Technology Institute has used their unique  
17 design to efficiently liquefy natural gas on a very  
18 small scale.

19 Normal liquefaction process, liquification  
20 process are going on a very large scale, of large  
21 facilities. A 13,000-gallon-per-day facility may seem  
22 large, it certainly seemed large to me, but it was  
23 really small in the overall scheme of things.

24 High Mountain Fuels Partners is a 50 percent  
25 joint partnership with Linde and Waste Management.

1 Waste Management is responsible for the biomethane  
2 production, Linde is responsible for the LNG production  
3 and on-site storage, and the logistics and distribution  
4 to our nine different fueling facilities in California.  
5 We're the ones that do the fueling at the various  
6 locations and consume the LNG, renewable LNG in our  
7 truck feet.

8           It's really major milestones, over 2.7 million  
9 gallons are produced, a proven maximum and sustained  
10 capacity of over 14,000 gallons per day, consistent up  
11 time of greater than 80 percent.

12           A number of rewards, and we're really looking  
13 forward to building this second plant, with the help of  
14 the Energy Commission, at our Simi Valley Landfill, in  
15 Southern California, to even provide greater fueling  
16 capabilities to our fleet.

17           One of the issues that's challenged us is the  
18 energy prices at the pump. This chart is from the DOE,  
19 the Energy Information Agency, and the annual Energy  
20 Outlook Report. This is the 2010 report, based on 2009  
21 data. It's a little bit outdated and, actually, it's  
22 pretty easy to see why. I show this up there more for  
23 just a relative indication of where we are.

24           The upper lines, green and red, are their  
25 estimated projection of gasoline and diesel prices in

1 terms of dollars per million Btu. Just as a point of  
2 reference, the \$35 per million Btu is roughly equivalent  
3 to \$4 per gallon gasoline prices, which is, of course,  
4 what we're seeing today in California. So, this chart  
5 is a little bit outdated, we're already up to  
6 approximately, in California at least, the 35 per MM Btu  
7 level.

8           The lower blue line, on the other hand, is the  
9 natural gas price, it's actually -- since this chart was  
10 put together, it actually has gone down a little bit,  
11 the natural gas prices are even lower than this. This  
12 is the price at the pump, not the raw value of the  
13 natural gas, alone.

14           And this is one of the reasons, one of the many  
15 reasons why Waste Management is in the process of  
16 converting its fleet to natural gas because of the huge  
17 price savings on the price of the fuel by transitioning  
18 from petroleum to a natural gas. That's the good news.

19           The bad news is in order to produce a renewable  
20 natural gas, we're probably at approximately the black  
21 line, and I just threw this black line on here as a  
22 relative point of comparison.

23           While it's still cheaper to produce renewable  
24 natural gas than gasoline or diesel, it's more expensive  
25 than getting gas out of the pipeline and either using it

1 as CNG or LNG. There's a price difference. How in the  
2 world do we make up that price difference to make it  
3 worthwhile to invest in a renewable natural gas  
4 development project in California?

5 Well, RFS2 and the LCFS are important in this  
6 regard, we think. The problem is we don't have any  
7 experience and we don't know how to project long term  
8 the value of the LCFS and the RFS2 in terms of revenues,  
9 we just don't -- we have know way of knowing what those  
10 are going to be.

11 This is just a hypothetical example. If we  
12 produce, at Altamont, 13,000 gallons of renewable LNG  
13 per day, about a little bit less than 5 million gallons  
14 a year, it's about 400,000 million Btu per year, that's  
15 about 33,000 metric tons of CO2 GHG reduction.

16 Well, what's the value of the RINs under the  
17 RFS2?

18 Our consultants tell us that we think -- that  
19 they think our LNG, our renewable LNG we're producing is  
20 about 60 cents per gallon right now, but whether that's  
21 going to be true in one, two, three years, as you've  
22 heard throughout the day, the RFS2 and the value of  
23 your -- the value of the RINs could very well go up and  
24 down, or sideways, we really don't know where it's going  
25 to go. And at 60 cents per gallon, though, that's \$7

1 per million Btu. What's the value of the low-carbon  
2 fuel standard? Well, again, that's likewise  
3 speculative. A lot of folks were talking about maybe 10  
4 to 15 dollars per metric tone of CO<sub>2</sub>E. That translates  
5 then, at 15, to 1.25 per million Btu.

6 But lately, with all of the uncertainty over the  
7 LCSF, and there really hasn't been any trades, and how  
8 do you do a trade, and this sort of thing, that's just a  
9 significant uncertainty there.

10 But if it is valued at \$7 per million Btu under  
11 RFS2, or \$1.25 under LCFS, that's about \$8, a little  
12 over \$8 per million Btu. If the basic fuel value of  
13 natural gas is \$4, the potential credit value is twice  
14 the value of the fuel, if it's \$8.

15 If you take a look at the pump value of maybe \$8  
16 to \$10 from a million Btu at the pump, for the natural  
17 gas, so at least a doubling, potentially, of the value.

18 So, there is a significant benefit to this. The  
19 problem is how do I got to the bank with that? How do I  
20 build a \$15.5 million plant betting that I'm going to be  
21 able to get this \$1.25, or \$8 per million Btu to  
22 supplement the -- otherwise, just the raw value of the  
23 fuel?

24 So, this is the major concern that we have is  
25 just this uncertainty of what the RFS2 and the LCSF

1 really means in real dollars, on a sustained ongoing  
2 basis, enough to recover the capital cost of building a  
3 \$15 or \$20 million plant.

4 Waste Management isn't only looking at renewable  
5 natural gas. We're looking at the 50 million plus tons  
6 per year of organic waste that we manage.

7 We kind of put this pyramid together of what we  
8 think the overall potential value of these materials,  
9 and other than putting it into a landfill, the next most  
10 valuable thing is pulling it out and using it as  
11 compost, and processing it that way.

12 But even better than that, we think generating  
13 electricity and producing power, producing  
14 transportation fuels is still a step up. Maybe making  
15 ethanol, and we've invested in a number of companies  
16 that are able to do these things.

17 And, potentially, gasoline, transportation,  
18 ultimately consumer chemicals or industrial chemicals  
19 produced from these organic waste in the landfills.

20 So, Waste Management is investing in a number of  
21 partners, that I've listed here. Terrabon, for example,  
22 is a company that makes organic salts that can be  
23 blended into the refining process to lower the carbon  
24 intensity of refined gasoline.

25 Enerkem is a gasification technology. S4 Energy

1 is a gasification technology. Genomatica is a San Diego  
2 firm that is looking at taking materials, chemicals in  
3 the waste stream and converting the waste into useful  
4 consumer and industrial chemical products.

5 So, we're all excited about where the future is,  
6 but we -- it's a question of getting there and trying to  
7 make money in the interim process.

8 In summary, with respect to biogas resources,  
9 they are readily available in landfills and waste  
10 materials, publicly owned treatment works. Waste  
11 derived fuels have, really, the lowest carbon intensity.  
12 We can't imagine how any other source of fuel is going  
13 to have a lower carbon intensity than a waste-based  
14 fuel.

15 Renewable LNG and CNG is cheaper than diesel,  
16 and that's one of the reasons we're heading that  
17 direction, but it's -- but it's more expensive than  
18 fossil LNG and we need to rely on programs, like RFS2,  
19 and the Low-Carbon Fuel Standard, and the AB118 program  
20 to bridge the gap so that we can build these facilities,  
21 and get this product out there.

22 And that's exactly what government can do to  
23 help is continue to provide incentive programs. But  
24 more importantly than just throwing up incentive  
25 programs up there, we really want to have there be

1 maintained predictability. And so we can hopefully --  
2 well, we don't feel we can count on 60 cents a gallon  
3 LNG under the RFS2, or even a 1.25 per million Btu for  
4 low-carbon fuel standard.

5 To the extent that that kind of predictability  
6 can be brought into the process, so we can rely on these  
7 as a source of revenue to support these investments,  
8 that is really the most important thing that can happen  
9 on a go-forward basis, from our viewpoint.

10 So, appreciate it. Maybe someday we'll see more  
11 and more vehicles like this, where they're closing the  
12 loop and running on rubbish to provide a transportation  
13 fuel. Thank you.

14 VICE CHAIR BOYD: Thank you, Chuck, great job.  
15 I have no questions.

16 MR. SCHREMP: Any questions from the people in  
17 the audience?

18 There'll be a short, three-minute break while we  
19 resolve a technical difficulty.

20 (Recess at 4:01 p.m.)

21 (Reconvene at 4:05 p.m.)

22 MR. SCHREMP: This is the last of my three  
23 presentations and it will be covering our crude oil  
24 import forecast, our preliminary one, and some  
25 background on the high-carbon intensity crude oil

1 screening process, or HCICO, to abbreviate that  
2 initialization.

3           So, crude oil, a funny thing happened since last  
4 time. You might notice that this didn't keep going  
5 down, it actually went up a little bit. Yes, in fact  
6 that's what has happened and that's primarily because of  
7 the increased activity in the bakken formation, mainly  
8 the Dakotas, a little bit of Colorado.

9           There's been some significant drilling activity,  
10 using an existing, an older technology that you hear  
11 common for natural gas, fracking is also being applied  
12 in the extraction of crude oil, as well as continued  
13 development of the Gulf Coast federal continental shelf.

14           So, there's been a rebound in domestic crude oil  
15 production in the United States, whereas we've seen a  
16 continued decline in Alaska, and California, and the  
17 rest of the U.S. in the last couple of years.

18           This is a close up of California's three  
19 components, the federal offshore, our shelves has been  
20 declining in state waters and on onshore. The biggest  
21 decline has been -- or recent has been the onshore  
22 portion.

23           There was a little bit of a rebound in the  
24 federal OCS in California waters, so in 2009 to 2010.

25           The much longer view, been producing oil for a

1 long time in California, but taking into context that  
2 nearly 29 billion cumulative barrels of production,  
3 still only about 10 and a half months of global demand,  
4 2011 global demand at a very high level, over 89 million  
5 barrels a day.

6           So, we've seen some ups and downs related to  
7 either rebound in the economy, wharf footing,  
8 depression, introduction of enhanced oil recovery, but  
9 ultimately a peak and then a downward trajectory that  
10 you see in most crude oil fields in the world. Not  
11 particularly in California.

12           So, here are some of the numbers. I don't have  
13 to go through all of them, but just point you to the  
14 middle bullets that there's been some significant  
15 decline in California and Alaska, and the rest of the  
16 U.S. is 40 percent. It would have been more except for  
17 that rebound that you saw.

18           So the rate of decline has eased somewhat in  
19 California, but with two more years of data, but not  
20 that much. And I'll talk about that in just a minute.

21           So, here are our sources of water-borne crude  
22 oil. We look at water-borne crude oil because this is  
23 an import infrastructure issue. And as you can see,  
24 over the last several years the total water-borne  
25 imports have fallen, so there is some implied spare

1 capacity that has developed in the crude oil import  
2 capacity for infrastructure. And this is primarily due  
3 to economic downturn, the five-year decline in gasoline  
4 demand in California that we've experienced.

5           So, but when Alaska goes down, it's displaced by  
6 increased foreign, and when California goes down it will  
7 be displaced by water-borne imports, unless the total  
8 demand for crude oil declines in California because of  
9 product demand and lower utilization rates at  
10 refineries.

11           So, just historically, Alaska, I mean total  
12 imports have increased, but as you saw the Alaska  
13 portion is down, it's really on the foreign side. So,  
14 those foreign barrels increasing at an annual rate of  
15 5.5 percent per year, so rather significant, and up 71  
16 percent.

17           So, when we do a forecast, what do we expect in  
18 the future? Well, we look at -- we look at how the  
19 refineries operate in California, how we anticipate  
20 them, or what our assumptions are moving forward for  
21 their operations.

22           We also look at California's existing crude oil  
23 production and its rate of decline, steady, is it  
24 accelerating, is it decelerating, and so we do a bounded  
25 forecast on that.

1           So, we take these two elements together and it  
2 will yield incremental barrels of crude oil that wants  
3 to come into this market over the water because, once  
4 again, no pipeline is bringing crude oil to California.

5           So what has happened? One of these elements is  
6 the refineries and their utilization rates. So, what is  
7 that? Well, I have a certain process -- a capability to  
8 process crude oil at my existing facility and I run a  
9 certain amount of crude oil through there, and divide  
10 one by the other and you get a utilization rate.

11           Simply put, this is one element moving forward  
12 in our assumptions, does the utilization rate remain  
13 steady throughout the forecast period? We are assuming  
14 it will and we are going to be looking at two different  
15 rates.

16           However, the refining capacity is another  
17 matter. In this go-round for the IEPR we're doing  
18 something that we haven't done before, we're looking at  
19 changing the trajectory of refining capacity in  
20 California to look at a scenario where it actually  
21 declines.

22           Now, why would we do this? As I mentioned  
23 before, 2009 forecast for gassing demand shows a  
24 decline, primarily due to CAFÉ standards improving and  
25 increased use of renewable fuels, both under RFS2 and

1 the LCFS.

2           So, that will create a growing imbalance in the  
3 refining sector. What do I mean by that? They'll have  
4 more gasoline than they need when they process crude oil  
5 and they'll be lacking in diesel that can be imported,  
6 and jet fuel, for that matter. But this is a kind of  
7 growing imbalance for primarily gasoline producing  
8 machines that you might start to go down the path as the  
9 European structure, where you have to have a large  
10 imbalance, more gasoline, and less diesel.

11           So what happens is the economics of operating a  
12 refinery in California can start to change on the  
13 gassing side of the equation, and the diesel side, and  
14 ultimately you could see some pressure for a  
15 consolidation of assets in California.

16           Not unheard of, people look at the high refining  
17 margins in California and say, well, they're the highest  
18 in the United States just about, they must be the most  
19 lucrative. Well, no, those are just margins, the  
20 difference between crude oil and product prices.

21           What you do not see is what are their operating  
22 costs? Those are, like the margins, some of the highest  
23 in the United States. So, their actual profitability is  
24 not reflective in those margins, those just apparent  
25 margins.

1           So, where you see announcements of companies  
2 looking at maybe consolidating some operations in  
3 California, those are not maybe just idle threats, those  
4 are looking at their entire global and even U.S.  
5 portfolios and saying here are some of the low profit or  
6 even some loss leaders in refining assets.

7           So, we think that some refinery consolidation is  
8 certainly feasible, therefore, we want to include a  
9 projection of a decline under one of the scenarios  
10 because that will impact our crude oil import forecast.

11           However, it will have the opposite effect for  
12 the infrastructure to import petroleum hydrocarbons  
13 because if you don't process crude and make the products  
14 here, you have to import the difference.

15           So, the decline rate, the other piece of the pie  
16 to perform the forecast is what is the decline rate  
17 doing? And this is remarkably similar to 2009. The  
18 actual, the low decline rate is 2.2 percent, that's the  
19 most recent year.

20           And you may say, well, why do you use that, I  
21 mean what was it over the last two years? Well,  
22 actually, 3.3 percent.

23           So, this is sort of looking at over the last ten  
24 years, this is probably one of the lowest rates. Not a  
25 surprise. Very high prices of crude oil in California

1 and increased drilling activity, so there has been --  
2 this is rather shallow.

3 A steeper rate is the ten-year average. But  
4 even, as I said, if I took a two-year average it was  
5 3.3, so we're still within the bounds.

6 And that is very similar to two years ago when  
7 it was 3.2 on the steeper decline rate.

8 So, this sets the table of how much incremental  
9 crude oil one would need assuming refineries kept  
10 operating at the same level of capacity and the same  
11 level of utilization.

12 So, here are our assumptions and feel free to  
13 weigh in, comments here today, after the fact, before  
14 the 23<sup>rd</sup>, as was stated for the comment period.

15 So, we're just looking at bounding this. What  
16 are some, maybe, of the sort of larger import forecasts,  
17 and that's taking the steeper decline rate in the  
18 bottom, and that's taking a flat refining capacity, no  
19 refinery creep, no expansion in California, and a higher  
20 utilization rate over the last ten years of 90 percent.

21 And, yes, some will say, well, isn't there a  
22 refinery in Big West that could become -- come back and  
23 in service? They've talked about that, very true.

24 However, they're not going to use any crude oil. The  
25 game plan is to take unfinished oils and process it at

1 the facility to produce gasoline diesel components,  
2 rather than crude oil. So, that's not an incremental  
3 crude oil demand in the system for our assumptions here.

4 So, what this does is actually dramatically  
5 change the need for incremental crude oil into  
6 California from what we had two years ago as 235 million  
7 incremental barrels per year, by the end of the forecast  
8 period, now down to 104.

9 Still significant, still nearly a third increase  
10 from the 2010 levels, so still an infrastructure issue.  
11 And this is especially for, say, Southern California,  
12 which is about, I think, 60 percent of the imports.

13 The low forecast, changing our assumptions, has  
14 a different outlook. We're using the less steep decline  
15 rate, 2.2. We're using a more near term lower  
16 utilization rate, 88, and we're introducing this  
17 refining capacity decline.

18 Now, would it gradually go down over time? No.  
19 If there was a refinery consolidation, it would occur  
20 all at once, so you see a step change down. But this is  
21 just to illustrate over the forecast period a decline of  
22 total capacity and what it can mean for imports in any  
23 particular year.

24 So doing this, compared to last time, we had 147  
25 million more barrels over the forecast period, and now

1 it's only 22, so that's a remarkably different outcome  
2 using this new assumption about refining capacity.

3           So, our focus is primarily in Southern  
4 California. No disrespect to Northern California, there  
5 are some issues there and we will be exploring them in  
6 our report.

7           But there is a new infrastructure that's been  
8 discussed in the Port of Long Beach, that's Pier Echo.  
9 Don't know where this stands and if it has legs, and  
10 we'll continue to move forward. Certainly, the Ports of  
11 L.A., Long Beach do not need to brand-new import  
12 terminals to handle incremental crude oil, only one.

13           Pier 400 -- berth 408 and Pier 400 has been at  
14 it a long time, that's Dave Wright. They've been  
15 working tirelessly and this has been going on for  
16 multiple IEPR cycles, so still nothing, yet. But we  
17 don't know at the end of the day what's ultimately going  
18 to be happening here, but this will require a  
19 significant amount of investment, partnering with  
20 clients to sign up to long term.

21           So, there is some uncertainty about moving  
22 forward, especially when we present these scenarios in  
23 the crude oil import arena.

24           Any questions on that before I go on? Yes,  
25 John?

1           MR. BRAUTIGAN: Jon Brautigam, with Valero.  
2 When you looked at your declining capacity utilization  
3 case, which is based on I'm assuming, like you said your  
4 future CAFÉ projections and other things, did you put a  
5 component in there for AB32, where all of the sudden the  
6 California refineries are penalized because they have  
7 stationary source emissions that they have to offset,  
8 and the foreign imports of the CARBOB wouldn't have that  
9 penalty?

10           MR. SCHREMP: We did not assume that AB32 would  
11 be a driver for some refinery consolidation. We  
12 understand that AB32 will likely incur some cost, either  
13 on the investment side for refining infrastructure  
14 and/or the purchase of carbon KRESS that will have some  
15 positive costs that we think will be passed along to  
16 consumers in the long run.

17           Does -- is that a regulation that is not  
18 existent in other parts of the United States or other  
19 parts of the world? Yes, that's true, so there can be  
20 introduction of sort of a new cost element in refining  
21 operations in California. But we also recognize that in  
22 other parts of the world there are some other  
23 regulations that refineries in, say, Europe are under,  
24 that do have incremental costs that, say, aren't  
25 currently existent in California, so there are

1 differences.

2           But I think the United States, John, sort of the  
3 near term or close-by competition, there is not an AB32  
4 component in the United States at this time.

5           Well, if there are no other crude oil questions,  
6 I'll continue.

7           High carbon intensity crude oil, or HCICO, is an  
8 element of the California low-carbon fuel standard.  
9 And, essentially, what we've been participating, some  
10 technical workgroup associated with this element of the  
11 regulation, and providing some analysis. And this  
12 regulation does look at crude oils in terms of their  
13 carbon intensity, and that has to do with how they're  
14 produced and brought to market. And it's really in the  
15 production side, not necessarily the transportation  
16 side, because all the crude oils have to be, for  
17 example, transported in marine vessels at some time to  
18 California.

19           So, we've done a lot of work in this area.  
20 There are four categories that can trigger a fail and be  
21 put into a basket of potential high carbon crude, as the  
22 Air Resources Board has structured this element of the  
23 regulation.

24           We've done some work on this, you're welcome to  
25 go look at the details of it, here's the link. But

1 essentially we looked at marketable crude oil names, so  
2 MCONS, and I apologize for the acronyms, 251 of them, so  
3 quite a few different crude oils available on Planet  
4 Earth, and quite a few countries, over 47 of them.

5 This table is only meant to illustrate the  
6 diversity of crude oil country sources. These are  
7 marketable crude oil names, they are country sources,  
8 and the number of different crudes from each of the  
9 countries.

10 You'll notice the highlights of red, those are  
11 countries under the ARB's regulation that were  
12 grandfathered, 206 baseline countries and then, you  
13 know, exempt from this element of the regulation.

14 So, you can see there were a certain amount of  
15 crude oils coming from those countries and then that's  
16 changed. In fact, in 2010, although it does say one on  
17 this slide, that's a bit old, I think there were no  
18 crude oil imports from Mexico in 2010 whatsoever in  
19 California.

20 So, the screen was performed, the vast majority  
21 of the near 75 percent of the crude oils received a  
22 pass. And it's interesting to note, even if you were to  
23 screen the grandfathered crude oils from outside of  
24 California, they would pass, there wouldn't be any  
25 fails.

1           However, grandfathered crude oil, say, from  
2 inside of California does have a significant portion of  
3 thermally enhanced oil recovery crude oil, and so that  
4 certainly would fall under the potential high carbon  
5 category, if you were to screen those.

6           So, we looked at the fails and eight of the 45  
7 were imported during 2009. And then -- and here is just  
8 sort of list of which ones failed or the number,  
9 depending on the category. Flaring, depending on  
10 enhanced oil recovery; mining, which occurs in Canada,  
11 the second to the last bullet.

12           And then you have things called upgraders,  
13 taking a crude oil and actually sort of partially  
14 cooking it and getting up with a lighter crude oil  
15 that's already been partially processed. And that's  
16 something that can occur in Canada, and is also  
17 occurring in Venezuela.

18           So, just looking at the total number of counts,  
19 not adjusting for some crude oils are available in  
20 larger quantities, and other -- here's just a scorecard  
21 of why they were placed into the potential high carbon  
22 categories and it's about -- according to this it's  
23 about, you know, a little over 20 percent of total  
24 numbers.

25           This is looking at 2010 imports to say, well,

1 did any of those come into California in the most recent  
2 period? And this is up, as I said, through November of  
3 2010. And the answer is yes. And it's about, I think  
4 about 16 percent of total foreign imports, but we use  
5 about half of that as foreign. So, it's about, you  
6 know, 70 percent of total crude oil imports for all uses  
7 during this period of time.

8           Now, the process of the high carbon crude oils  
9 can -- the incremental carbon can be offset. Refineries  
10 would have to use greater amounts of renewable fuels in  
11 the correct carbon intensities. However, it becomes  
12 increasingly more difficult. Not only does the LCFS  
13 regulations become more and more difficult as time goes  
14 by, it starts off easy, gets progressively more  
15 difficult, so offsetting becomes even harder.

16           So, to put some of this in context, if they were  
17 to use the same quantity, the refiners, in 2011, of  
18 these high carbon -- potential high carbon crudes, the  
19 offset would be, basically, you'd have to use nearly all  
20 California and Brazilian ethanol in all of the gasoline  
21 today.

22           So, that's unlikely. From talking to the  
23 refiners they are looking, and have looked, and have  
24 been purchasing alternative crudes, instead of these  
25 potential high carbons because understanding that the

1 offset is challenging, and especially for those who  
2 would like to build up credits to use in latter years  
3 under the LCFS program, itself. Oh, by which that the  
4 credits don't have an expiration date, as they do under  
5 the federal RFS2, which we think is a good idea.

6 So, looking at a more reasonable high carbon  
7 crude oil mix of, say, two percent, it still becomes  
8 increasingly challenging, especially you can reach some  
9 feasible solutions by 2013, meaning that kind of low  
10 carbon ethanol doesn't yet exist. And it would be  
11 cellulosic, but it just doesn't exist right now.

12 So, we think, as part of our assumptions moving  
13 forward, that potentially potential high carbon crude  
14 oils are not going to be available to refiners  
15 effectively speaking for purposes of this.

16 And so when you do a volume weighted adjustment  
17 the percentage does change a little bit, so it becomes  
18 more like 26 percent of the foreign crude oils in this  
19 snapshot for 2010 are in the potential high carbon  
20 category.

21 And you also want to recognize that why I keep  
22 saying potential, it is just that. Companies can  
23 provide additional information to the Air Resources  
24 Board, staff identifying why a particular crude oil may  
25 not be high carbon.

1           I'll give you an example. Under the flaring  
2 criteria, basically all of Russia crude oil production,  
3 you know, in excess of 9 million barrels a day, is  
4 higher than the level set by ARB, so it would be a  
5 potential high carbon.

6           Well, there is some crude oil that is, say,  
7 primary production, that is from a group of fields that  
8 can possibly have lower than the level set by ARB and  
9 would, therefore, fall out of the potential high carbon  
10 and then be able to be used, but you need to demonstrate  
11 that with, you know, a sufficient amount of detailed  
12 information on its production.

13           So, there is the possibility to do that under  
14 this process, so ARB does have that.

15           So, I just wanted to reiterate that companies  
16 have been changing their purchasing decisions. From  
17 what we understand and the information we've been  
18 collecting confidentially, that's usually resulting in a  
19 higher acquisition cost for crude oil that we do think  
20 will be passed through to consumers in the long run.

21           And also, I think as Malachi mentioned this  
22 morning, energy security is something that we're going  
23 to be looking at under some aspects of our analysis in  
24 various issues and, certainly, this is an issue that  
25 does have a potential energy security implication.

1 Meaning that, say, Canadian crude oils, which is  
2 probably a very high energy security source, relative to  
3 others, would be precluded, and so that has an energy  
4 security implication, as just an example.

5 Those complete my comments, any questions?

6 MS. GREY: I don't see a bird.

7 MR. SCHREMP: It's right back here. Gina's  
8 referring to some monthly Western States presentations I  
9 do that almost always have a bird picture at the end.  
10 Different audience, I just didn't -- you know, I didn't  
11 want to shock you.

12 Any questions from the guys?

13 VICE CHAIR BOYD: No questions. I'm still  
14 trying to figure out the vast wasteland conclusion here,  
15 but anyway let's let Gina comment on it.

16 MR. SCHREMP: Well, unless we have any questions  
17 right now on my slides, from the audience, and it looks  
18 like we do in Dwight Stevenson, Tesoro.

19 MR. STEVENSON: Thank you, Gordon. At the risk  
20 of making a statement, I'll ask a question and see what  
21 your answer is. If you're going to slice out some of  
22 the potential crude supply in the California, and  
23 California refiners are going to have to go further out  
24 to get that crude, what impact do you think that's going  
25 to have on the entire market as opposed to just that

1 seven, eight percent? Do you think that the whole crude  
2 market's going to shift up in price or do you think only  
3 that seven or eight percent's going to shift up in  
4 price? How's that for a loaded question?

5 MR. SCHREMP: Well, we do -- I mean, crude oil  
6 is a global commodity, impacted and it seems like more  
7 recently significantly impacted by geopolitical events  
8 and cash flows in and out of futures markets, and other  
9 commodity futures market opportunities. So, those  
10 prices will elevate up and down.

11 There are differences, depending on quality,  
12 that do occur. And so, I mean, companies having to  
13 go -- I mean, let me just back up. I mean, from what we  
14 understand in talking to the refiners, they're looking  
15 at alternative crude oils, they don't necessarily look  
16 at an alternative crude oil that is less expensive  
17 overall, meaning they have to incorporate the  
18 acquisition price and its impact on the operations of  
19 the facility.

20 MR. STEVENSON: Uh-hum.

21 MR. SCHREMP: So, refiners are using, likely,  
22 the optimal sources of crude oil for their price points,  
23 operational economics. So, going out and changing that  
24 dynamic we understand is seeking out a -- is turning out  
25 to be a higher cost crude oil, we think that's going to

1 increase the acquisition cost for crude oils in  
2 California from that mix.

3           So I think, yes, they'll -- I mean that's a way  
4 of looking and saying the whole entire complex is going  
5 to be a bit more expensive. You're talking from the  
6 California perspective rather than, say, affecting  
7 global crude oil prices?

8           MR. STEVENSON: No, I meant the California,  
9 yeah.

10           MR. SCHREMP: Yeah, we think that costs of crude  
11 oil -- the crude oil acquisition price for California  
12 refiners will net increase, yes.

13           MR. STEVENSON: Thank you.

14           MR. SCHREMP: Seeing no other questions from the  
15 audience, we'll go ahead and we have Gina Grey will be  
16 our next speaker.

17           MS. GREY: All right, thank you. Good  
18 afternoon, Commissioner Boyd and to the entire audience  
19 here that's still left in the room. And I assume  
20 there's some on by WebEx today.

21           My name is Gina Grey and I am here representing  
22 the Western States Petroleum Association and my position  
23 there is Vice President of Strategic Policy and Fuels,  
24 and that's for our entire WSPA organization. And then I  
25 also oversee three states, which is Arizona, Nevada and

1 Hawaii.

2           And I think I'd like to just start with a couple  
3 of general comments, based on what I've been listening  
4 to today. And, you know, one of them goes to sort of  
5 this sense that I got from some people that, especially  
6 with John Brautigam's presentation, after that, that the  
7 oil industry is the purveyor of doom and gloom  
8 scenarios.

9           And I know that might be felt by some when we do  
10 get up here and we tend to talk about all of the  
11 challenges, and the barriers, and the costs and  
12 everything that are standing in the way of alternative  
13 and renewable fuel expansion into the State.

14           But I personally prefer to think of us as more  
15 purveyors of reality because, as people said, the people  
16 that are in this room today were invited because they  
17 have experience in transportation fuels. And,  
18 certainly, the petroleum industry has a lot of  
19 experience in transportation fuels, that I can say.

20           And so in some ways I think what you are hearing  
21 today is perhaps a dose of reality on some of these  
22 aspects. It may not be shared by everyone, people have  
23 different perspectives on how things are moving.

24           But if you do take an historical look back at  
25 how long certain things take to come into the

1 marketplace and, you know, I've been with WSPA for 22  
2 years, and I can certainly say that I've sat through my  
3 fair share of alternative and renewable fuel workshops  
4 and conferences, and have heard these discussions quite  
5 a bit. Not to say that things haven't progressed over  
6 those 22 years.

7           But I think the time frame within a lot of these  
8 things takes place often is much longer than anyone  
9 would anticipate or even want, and there are a lot of  
10 issues that tend to crop up, and you heard some today.  
11 Some are in the investment arena, some are in the  
12 permitting arena, you know, some are in standards, and  
13 codes, et cetera, and all these things tend to crop up.

14           And often these transitions into new sort of  
15 ways of thinking of things and new transportation fuel  
16 scenarios don't take place within the time frame that  
17 people want, so that's just one introductory comment.

18           And so I would just say this who WSPA is. We  
19 have 26 petroleum companies in six western states. And  
20 what you will see is this is our sort of first, opening  
21 slide and at the end you will see our closing slide,  
22 which actually indicates that even though we are sort of  
23 big oil, people traditionally think that we are only in  
24 petroleum, our companies actually are very heavily  
25 involved, investment-wise with their own dollars, in

1 terms of moving into the alternative and renewable fuels  
2 arena.

3           Okay. I took a little bit of liberty here with  
4 the Bowen Bill and tried to indicate that, obviously,  
5 the State goal, as was stated by Malachi at the  
6 beginning, was to reduce emissions and carbon from the  
7 transportation sector, and that the whole IEPR exercise  
8 is to do that, while ensuring adequate, reliable, and  
9 here was the WSPA twist, affordable supplies of  
10 transportation fuels.

11           And I think the Bowen Bill said "reliable,  
12 secure and diverse," so we've added in "affordable" in  
13 there, as well, as being one of the main goals.

14           I think it's quite a charge for the Energy  
15 Commission to have to -- this year, in particular, I  
16 would say, take on the role of trying to look at not  
17 only what's been occurring within the transportation  
18 fuel arena, but then to project out what's going to  
19 occur, I think that's the real challenge for this year's  
20 2011 IEPR. It's quite a tall order.

21           And, you know, everyone else talks about the  
22 three-legged stool, the vehicles, the fuels, and the  
23 consumers, but more than anything I think we would  
24 emphasize that it's critically important in this coming  
25 IEPR to make sure that all three of these are very

1 thoroughly vetted. Because typically, you know, I've  
2 heard a lot today about fuels, we heard a little bit  
3 about the vehicles, and we heard a little bit about the  
4 consumers. All three of those elements have to be  
5 working in sync, entirely, in order to have any movement  
6 forward on this, because if one of those doesn't work  
7 well, the rest fall apart.

8           And I think you heard Tim Carmichael, for  
9 example, talk about even though there are vast  
10 quantities of natural gas available the vehicles, the  
11 light-duty vehicles, for example, are not necessarily  
12 available in the market place. And, you know, he's not  
13 overly thrilled with that prospect.

14           And again, if you don't consider the consumer,  
15 that's the other critical piece of this.

16           So, I would say here that -- just let me move  
17 on. I've tried to portray here, really, the fact that  
18 this particular IEPR, you know, the focus is going to  
19 have to take into consideration some things that have  
20 not been there in the past.

21           And two of them, definitely, I think in the last  
22 IEPR RFS2 was discussed, and there was some  
23 consideration of that. But, certainly, the California  
24 LCFS program, Low Carbon Fuel Standard program is  
25 something that will be heavily focused on, hopefully,

1 this time around in the IEPR>

2 In 2009, when you did your last one and dealt  
3 with transportation fuels, that was the adoption year.  
4 This year is the year of implementation, the first year  
5 of implementation. And even so, as was pointed out  
6 earlier, there's a lot of gaps in the LCFS program even  
7 now, so we're kind of off to what I would coin as a soft  
8 start with the program. And as such, as the program  
9 continues to roll on, I think people are going to be  
10 needing to ask a lot more questions, a lot more details.  
11 Not just going with the optimistic everything's going to  
12 be fine and it will all work out type of scenario.

13 And, you know, we've dealt historically with  
14 fuel specifications, which is the fourth bullet here  
15 under mandates, but this is truly a transforming LCFS  
16 regulation, where it's attempting to revise the entire  
17 transportation fuels arena in the State. And because of  
18 that it's not just simply, well, we've tinkered with  
19 some specifications and the vehicles are there to  
20 receive these new fuel specs, it's totally transforming.

21 AB118, under incentives, that's been talked  
22 about a lot today and I think you've heard from a lot of  
23 the fuel folks that were represented the desire to have  
24 additional incentives from the AB118 or the California  
25 program, as well as all the other incentive, both the

1 federal monies and other monies that are flowing into  
2 those fuels to sort of kick start the entire scene.

3           And then I've listed out some considerations and  
4 challenges, that I'm not going to go through these, I  
5 just sort of wanted to point out what some of those are,  
6 and we've certainly heard a lot of those today.

7           And we're here today, basically, to talk about  
8 infrastructure and the distribution system.

9           Gordon did a good job of talking about what's  
10 going on in the port area, and I'm not going to belabor  
11 this, and I don't think there are a lot of answers to a  
12 lot of the questions that he posed so far. Other than I  
13 think, in addition to what he shared with us this  
14 afternoon, we also need to think a little bit about, you  
15 know, other than the, okay, here's what's happening to  
16 crude oil in the State, and here's what theoretically  
17 should be happening, therefore, in the ports and the  
18 terminals, I think we also need to be asking some  
19 additional questions.

20           You know, along the lines of, well, what if port  
21 infrastructure expansion is needed to handle crude oil  
22 and product imports, or petroleum product exports? And  
23 no one's really talked about the product exports,  
24 necessarily.

25           Depending on how our companies, and I'm not

1 forecasting anything here, I'm just saying there are  
2 definitely some possible scenarios for how the regulated  
3 parties might react to some of the things like the Low  
4 Carbon Fuel Standard, and there might be a possibility  
5 that they would say we are going to export our product  
6 offshore. So, again, that would mean some need to look  
7 at what the infrastructure is going to be needed at the  
8 port to handle those exports.

9           And definitely we talked about additional  
10 imports of crude oil from elsewhere in the world.

11           And then, also, port infrastructure expansion  
12 needed for alternative fuels and blend stocks to comply  
13 with both RS2 and the LCFS.

14           And then, thirdly, just the key here, which  
15 Gordon touched on, which is how long it takes to resolve  
16 issues at the port. And I think he mentioned Pier 400,  
17 which I've been told has -- I think it's ten years, now,  
18 that that's been worked, so it's taking a very long  
19 time. And traditionally these things seem to take a  
20 very long time in the ports.

21           And, of course, there's not only timing  
22 implications, there's also cost implications and energy  
23 security implications, too. And the question always  
24 comes up, well, who's going to bear all those costs?  
25 That's always the kicker.

1 All right. And, really, one of the key things  
2 that WSPA wants to get across today, and it flows from  
3 what Gordon was talking about in terms of the Low Carbon  
4 Fuel Standard, is the treatment that ARB has decided to  
5 adopt in the Low Carbon Fuel Standard for the treatment  
6 of crude oil, and how that all is going to be treated.

7 And Gordon's portrayal this afternoon showed the  
8 draft process that ARB staff has been working up to this  
9 point in time, and it shows sort of the differentiation  
10 approach that CARB is trying to achieve by saying  
11 worldwide there are some crude oils that are much more  
12 carbon intensive than others, and somehow we have to  
13 factor this into the process.

14 Scientifically, perhaps, and this is not a  
15 comment by WSPA, but scientifically folks could sit  
16 there and say maybe that makes sense. But there is more  
17 than science that needs to be considered in a lot of  
18 these decisions, as we move forward, to make sure if in  
19 fact the Low Carbon Fuel Standard is going to work and  
20 achieve what the goals are, some of these aspects that  
21 are being put into play are not conducive to that goal.

22 And I just wanted to put these two last bullets  
23 here in red because we're always being asked, well, when  
24 can the Commission enter into the debate, what does --  
25 who -- in terms of the stakeholders, when do you think

1 that you should engage?

2           And I would just like to point out that we think  
3 there are a couple of points in time here this year,  
4 with the ARB, when first of all they're will be some  
5 revisions, potentially made to the regulation. We're  
6 not too sure exactly when that particular hearing will  
7 be held, maybe in December of this year. It may be  
8 even, say, January or February next year, but definitely  
9 within the year there will be a hearing to address  
10 changes to that LCFS program.

11           We would invite you to weigh in at that hearing.

12           And periodic reviews that were required in the  
13 resolution that came out of the April 2009 Board  
14 Resolution. 2011, this year, as Gordon alluded to,  
15 there is an advisory panel of sort many stakeholders  
16 that are sitting around the table, trying to look at  
17 what the progress has been on this Low Carbon Fuel  
18 Standard, trying to determine are there changes that may  
19 be needed, et cetera.

20           And Gordon does sit on that advisory panel, and  
21 we would just, again, welcome the Energy Commission's  
22 input to that, as well as all the statistics,  
23 information, data that you folks carry and obtain from  
24 our industry, and others, under Pyra confidentiality,  
25 that would be very helpful as input to that process.

1           And I've just outlined for you here, in case you  
2 were unfamiliar with the advisory panel, here are all  
3 the topics that this advisory panel are supposed to look  
4 at this year, so you can see it's a very long list. And  
5 down towards the bottom, topic 14 is the high carbon  
6 intensity crude oil, which is one of the most important  
7 issues for our industry.

8           And again, just a plug, asking CEC to please  
9 provide input and guidance into that Periodic Review  
10 Panel, would be very helpful.

11           And I'll try not to go over the ground that  
12 Gordon's already talked about, I think he did an  
13 excellent job of trying to depict what the whole high  
14 carbon intensity crude oil issue is about.

15           But essentially, as I said earlier, it's an  
16 attempt to differentiate crude. And WSPA has said, from  
17 the beginning, that we disagree with any type of attempt  
18 to differentiate crude, particularly when you're trying  
19 to kick off a program of the magnitude and complexity  
20 that the Low Carbon Fuel Standard already is, on top of  
21 an RFS2 program, on top of everything else that our  
22 industry is being required to do, it just is not  
23 conducive to making sure a program like this is going to  
24 survive.

25           And the two points at the bottom here are really

1 the most critical ones that Gordon did mention, is what  
2 it does is it really creates a deficit if you use a high  
3 carbon intensity crude oil, and then you have to make  
4 that up somehow. And you have to make that up either  
5 through some kind of low carbon intensity blend stock,  
6 like an ethanol, cellulosic, otherwise.

7           And the question always comes up is are there  
8 going to be sufficient volumes of those types of blend  
9 stocks in order to offset the deficit?

10           And the last bullet here is just, you know, the  
11 implication to this is that there are going to be crude  
12 oils around the world, and whether they're the Canadian  
13 oil sands, or whether they're from Russia, or whether  
14 they're from some of these other areas that right now,  
15 through the crude oil screening process, appears to say  
16 that some of these crude oils around the world will be  
17 deemed to be high carbon intensity crude oil and,  
18 therefore, be penalized.

19           As Gordon says, your options as a refiner are  
20 pretty limited and it can create all sorts of unintended  
21 consequences in the market place if you select one of  
22 those options.

23           So, it's -- again, it's just very important to  
24 us to make sure, again going back to the Bowen Bill, and  
25 making sure that the transportation fuels and the energy

1 in the State are reliable, and adequate, and affordable,  
2 et cetera.

3 This particular provision, in the LCFS, works  
4 directly in opposition to that theory.

5 And I think Gordon showed this earlier and, you  
6 know, I think it's the half -- it's the glass that's  
7 half full or half empty. And some people look at this  
8 and say, oh, well, oil industry, what's your problem?  
9 You know, you have three-quarters of this pie to go and  
10 select from. And, of course, we're looking at the other  
11 piece of the pie and saying, you know, those are the  
12 pieces of the pie that traditionally we, as the  
13 refiners, may have been purchasing those crude oils.  
14 those crude oils are suited for our refineries and we  
15 just can't go out, necessarily, and purchase the rest of  
16 the pie. Plus, it raises us a whole slew of other  
17 issues, which are listed, some of them, on the next page  
18 here. And this is my second to the last slide.

19 And excuse me, my voice, I'm just getting over  
20 the flu.

21 Really, this crude differentiation approach,  
22 there are many, many implications that can arise out of  
23 this, and the one term that everyone probably has heard  
24 about is crude shuffling. And that's where basically,  
25 and just as an example, you're saying to the Canadian

1 oil sands, you know, you're no longer desirable, your  
2 crude oil, because it's deemed to be high carbon  
3 intensive. So, Canada says fine, we're going to send  
4 our crude oil over to Asia.

5 Well, the vessel that takes that crude oil over  
6 to the Far East, for example, goes a lot further to go  
7 to the Far East than it would have to, to come down into  
8 the port in California.

9 So, indirectly, you're creating excess  
10 greenhouse gas emissions by forcing this crude oil to go  
11 somewhere that's a further distance. So, that's what  
12 crude oil shuffling is.

13 There's obviously the energy security issue and  
14 many people have said that, you know, why would we turn  
15 away a neighboring country's crude oil? They tend to be  
16 a friendly country. So, again, when people raise energy  
17 security as an issue with petroleum, why would you try  
18 and discourage Canadian crude oil to come down.

19 And then mentioned earlier was the refinery  
20 configurations and, you know, those refineries have  
21 spent billions of dollars to configure themselves in a  
22 certain way to process certain types of crudes. It's  
23 not a very simple process to just change your crude  
24 slide overnight, if ever.

25 And then, you know, that could lead to other

1 consequences, as Gordon mentioned, in terms of  
2 consolidation, et cetera.

3           And then changes in amounts of crude oil  
4 processed, that's always a consideration, obviously. It  
5 would just be to drop your amount of crude oil that  
6 you're actually processing, and then that results in  
7 less product, less fuel.

8           Or as I mentioned earlier, another option might  
9 be to just export the product, so California doesn't see  
10 a drop.

11           And then infrastructure requirements for fuel,  
12 blend stocks needed to compensate for the HCICO deficit  
13 and, you know, that was, I think, briefly touched on by  
14 Gordon as well.

15           And I just listed out here some of the  
16 assumptions that we, as an industry, sort of have felt  
17 are being made by ARB, in the LCFS program. And these  
18 are all issues here that I think need to be asked by the  
19 Commission and to see if, in fact, these are valid or  
20 not valid.

21           I can't comment, especially being in a trade  
22 association, I don't have intimate knowledge of what  
23 each of our companies is about to do, or not do.

24           But, certainly, these are some of the real hard  
25 core, on-the-ground questions that typically have never

1 gotten asked because there's always an assumption that  
2 our industry will be in the State forever, and we'll be  
3 providing all the transportation fuel that's required on  
4 the petroleum side forever.

5           Okay. And here's the last slide, and this is  
6 the companion to the first one, where I said that we're  
7 all considered to be just petroleum companies and  
8 definitely not. We actually spend a significant amount,  
9 if not more than the majority, including the federal  
10 government, on the development of alternative and  
11 renewable fuels.

12           And I think my closing comments are just, you  
13 know, someone used the term earlier that this is -- the  
14 LCFS, in particular, is a grand experiment, and I would  
15 support that. I think out of all the programs that  
16 we've seen, it tends to be the one that's most like an  
17 experiment, particularly when it has the regulated party  
18 as the petroleum industry, basically. And we're being  
19 told that we need to go out there and either we produce  
20 the low carbon intensity fuels, or we blend someone  
21 else's product in order to achieve that low carbon  
22 intensity level, or we purchase credits off of someone  
23 who is producing that low carbon intensity fuel, as in  
24 electricity or potentially hydrogen, et cetera.

25           And I think the thing that people often lose

1 sight off, when we get into these alternative fuel  
2 discussions, are the volumes. And I think Malachi  
3 mentioned at the beginning, you know, 20 billion, with a  
4 "b", gallons of transportation fuel every year in this  
5 State.

6           And when you start hearing bout some of the  
7 amounts of alternative transportation fuels that are  
8 being produced, they're not in that realm.

9           And that's not to say that at some point in the  
10 future they won't be in that realm. But again, as I  
11 said earlier, timing is one of the critical factors here  
12 that, you know, is the industry, is the entire  
13 transportation fuels arena being provided enough time to  
14 transition?

15           And I know it seems like an eternity that we've  
16 been talking about these issues, and everyone says,  
17 well, why haven't things transitioned over, yet? Very  
18 good question and there are lot of reasons for that, and  
19 lot of them relate to things like cost, capital, all the  
20 issues about the incentives that people were talking  
21 about.

22           So, you know, the risks, the investments  
23 necessary.

24           And then just to close I would say one of the  
25 worse things that can happen is, and this traditionally

1 is what goes on in government, is there are programs  
2 that are put out that are very aggressive, and the LCFS  
3 program is one of them, the zero emission vehicle  
4 program is another, and there's probably tons of other  
5 examples, with the hope that at least it will spur  
6 industry to move forward.

7           And then as we move down the road and things  
8 aren't happening the way that folks wanted within the  
9 time frame, then those programs get changed. And this  
10 is something we've seen constantly happening.

11           Not to say that's bad, things have to evolve, et  
12 cetera. But what is lost in that whole evolution and  
13 changing of programs is the fact that people do need  
14 certainty, I heard that quite a bit today, in terms of  
15 making investments.

16           And stranded investments are not going to help  
17 anyone, they're not going to move low carbon intensity  
18 fuels out into the marketplace.

19           And so we would just close by saying, you know,  
20 the role for the California Energy Commission right now,  
21 in this IEPR, is really critical this year to start  
22 looking at all these questions in a very realistic  
23 manner, asking some very hard questions about the costs,  
24 et cetera, and not assuming that the entire low carbon  
25 intensity alternative renewable portfolios of fuels is

1 going to stand on an AB118 or an incentive-based, you  
2 know, footing. There needs to be more than that and  
3 often that comes down to things like timing, et cetera.

4 So, thank you. Anymore questions?

5 MR. OLSON: Thank you, Gina.

6 MS. GREY: Thank you.

7 MR. OLSON: Commissioner Boyd had to leave early  
8 for a flight, he apologizes for that. It doesn't show  
9 disinterest.

10 MS. GREY: That's okay.

11 MR. OLSON: And we'll have some -- he's going to  
12 have some follow up with the staff to go over what he  
13 missed here.

14 MS. GREY: Okay.

15 MR. OLSON: So, then I guess if there are any  
16 questions on Gina Grey's comments?

17 MS. GREY: Okay, thanks very much.

18 MR. OLSON: Thank you, Gina.

19 MR. SCHREMP: Thank you, Gina. We have two more  
20 speakers. John Brautigan will come up here and he has,  
21 I think, three more slides that were the tail end of his  
22 presentation this morning, that are associated with the  
23 high carbon intensity crude oil issue.

24 And then after John, we're going to go ahead and  
25 have Mike Waugh, who is from the California Air

1 Resources Board, who will also be speaking.

2 So, John.

3 MR. BRAUTIGAN: Okay, thank you. I'll try to  
4 keep this short. Gina, I'll accept the label of  
5 somebody that's trying to do an honest assessment and  
6 staying with reality, versus doom and gloom. That's all  
7 I'm trying to do.

8 We -- for instance, we've talked to the EPA on  
9 Tier 3 gasoline and we told them, yeah, we can do 10 ppm  
10 sulfur, we can do that, that's technically achievable.

11 But I filed the RFS2 production outlook reports  
12 for Valero, we produce 1.1 billion gallons a year of  
13 ethanol, at ten ethanol plants, and I know what we're  
14 looking at for future cellulosic or biodiesel production  
15 in our planning process. And I've ratcheted those back  
16 in the March report versus what was sent in, in August,  
17 things are just moving slower.

18 There will be electric vehicles out there, there  
19 will be cellulosic ethanol, there will be a lot of  
20 stuff, but just not enough, we believe, to meet the  
21 percent reduction standards in the LCFS, and not enough  
22 to meet the targets in the RFS2. So, we're just trying  
23 to be honest.

24 Anyway, okay, the question we were asked to  
25 answer was "Has the HCICO issue altered our purchasing

1 decisions?" Yes. Valero is trying to minimize its  
2 HCICO purchases this year and we do not plan on buying  
3 any for delivery after September 30<sup>th</sup> of this year, when  
4 it can no longer be treated as normal crude under the  
5 advisory that CARB issued.

6 We think HCICO disadvantages California  
7 refiners. We would urge Gordon and staff to maybe  
8 reconsider. We've got AB32 coming in, just for impacts  
9 of California refiner rates in the future, raising our  
10 cost, but not raising importer's.

11 We've got the renewable electricity standard  
12 that's going to raise our electric costs.

13 We've got the HCICO issue, going to raise our  
14 crude costs.

15 And we have potentially new competition from  
16 this pipeline coming from Utah into Nevada.

17 You know, the things are lining up not in favor  
18 of California refiners, so that you might see some  
19 more -- I don't know what's going to happen, it's  
20 just -- but there's the pressures and not in the  
21 direction to be upping capacity or necessarily to  
22 maintain all the capacity that's there, potentially.  
23 Okay.

24 The other thing is some California baseline  
25 crudes have a higher CI than non-baseline HCICO crude,

1 so it's just disadvantaging these crudes from being run  
2 at California refineries.

3           How easy is it to difficult -- or how easy --  
4 somebody didn't proof this slide very good. Or how  
5 difficult is it to offset the incremental carbon debit  
6 of HCICO during 2011 and would it be more difficult in  
7 2015?

8           If you use the default number of 20, and you  
9 subtract that from 6.3, you get about a 13 CI debit that  
10 you would have to apply to the corresponding carb diesel  
11 that you produce.

12           Now, remember the baseline's running at 98, so  
13 that's like a 13 percent increase in CI. The whole LCFS  
14 program, by 2020, is looking to reduce the pool by ten,  
15 so it's almost like trying to have, for that portion of  
16 your products that comes from high carbon intensity  
17 crude, it's like trying to meet the 2020 goals in 2011.

18           Now, what's out there? There's 80 to 90 CI  
19 ethanol out there. Okay. Some of the plants, we do  
20 know -- I do know of one, we believe one producer did  
21 change an energy mix and is potentially using biomass  
22 instead of coal. A lot of plants just looked at their  
23 energy consumption and said, hey, CARB's default values  
24 were too conservative, we can refile.

25           And Valero's looked at this and is deciding what

1 we want to do. We can refile and get a lower CI for the  
2 Midwest corn ethanol plants.

3           The problem is you can't necessarily get a  
4 hundred percent, 80 CI ethanol. A lot of the ethanol is  
5 marketed by marketing companies and what they're doing  
6 is agreeing to contracts that they will supply you with  
7 maybe 90 or less CI ethanol. That way it doesn't tie  
8 them down to a specific number and sourcing it from a  
9 specific ethanol plant, and maybe that plant having  
10 trouble and not being able to switch barrels.

11           So, just because there's plants at 80 out there  
12 doesn't mean you can run a hundred percent 80 CI  
13 ethanol.

14           And if you look at the volume metrics again,  
15 okay, you know, I got 9/10s of a gallon of CARBOB, 1/10<sup>th</sup>  
16 of a gallon of ethanol, and then I got an energy content  
17 of 70 percent of the CARBOB for the ethanol, it's just  
18 trying to offset the higher carbon intensity of the  
19 HCICO just gets very hard.

20           If you could get all 80 CI ethanol in 2011, you  
21 could maybe run, and this will vary from refinery to  
22 refinery, but 50 percent high carbon intensity crude in  
23 2011, okay. And this would be if we weren't having the  
24 ability to treat it as normal, okay.

25           And in 2015, probably none, so it will have a

1 big impact, okay.

2           So, it's just -- I don't know, to us it just  
3 doesn't make much sense. You're negatively impacting  
4 California refiners, you're eliminating as much as 25  
5 percent of the crudes that we were running. The crude's  
6 still going to be run, it's a global commodity. It's  
7 not going to -- Nigeria isn't going to care and stop  
8 flaring, they're going to base their flare gas -- their  
9 gas recovery on economics and we're not going to be able  
10 to get any good information out of the producers.

11           They don't -- I'm sorry, but the California  
12 market is not big enough, a big producer doesn't care if  
13 his crude is excluded from the California market.

14           Now, I know the Canadians would probably  
15 disagree with that. I'm talking about foreign producers  
16 that don't even know about this when we go and talk to  
17 them.

18           Like when we go and talk to the Russians that  
19 produce ESPO, I mean they think we're crazy, they have  
20 no idea what we're talking about, okay.

21           So, that's it for my comments. Thank you. Any  
22 questions?

23           MR. OLSON: No questions.

24           MR. SCHREMP: Well, if there are no questions  
25 from the audience, I'd like to have Mike Waugh, from the

1 California Air Resources Board, come to the microphone.

2 MR. WAUGH: Good afternoon. I'm Mike Waugh, I'm  
3 Chief of the Criteria Pollutants Branch at the Air  
4 Resources Board, and it is my branch that has been very  
5 busy. We're working on fuel specs for CNG as a  
6 transportation fuel, E85, E10 certification fuel,  
7 biodiesel, and renewable diesel, and also we're  
8 responsible for the Low Carbon Fuel Standard.

9 So, when I say that we've been busy, I guess  
10 that's the take home message that we've been working  
11 hard and been working with our stakeholders.

12 I'd just make a few comments and some global  
13 comments, and a couple of detailed comments.

14 First of all, the Low Carbon Fuel Standard is a  
15 performance-based standard, and so all the alternate  
16 fuels are welcome, CNG, RNG, electricity, hydrogen, E85.  
17 So, today's presentations, in terms of the status of  
18 that development, it was really good to hear today that  
19 LCFS, by being a performance-based standard, it provides  
20 flexibility and also drives innovation, and that is the  
21 intent of the LCFS. And I think you saw some of that  
22 today.

23 You know, we do understand the challenges ahead  
24 of meeting the LCFS and RFS2. I think Gordon said this  
25 morning that no additional ethanol needs to be brought

1 to California to meet the LCFS, and that's consistent  
2 with our analysis, it just has to be a lower carbon  
3 intensity.

4 And the lower carbon intensity, really, you're  
5 really talking about cellulosic ethanol. And I think  
6 several speakers today have talked about the fact that  
7 we're not seeing the rollout of cellulosic ethanol and  
8 that is creating a challenge for the RFS2 and a  
9 challenge for the LCFS.

10 One thing of the LCFS is that it's back-loaded.  
11 The early years are pretty modest goals. For example,  
12 this year the CI has to be reduced by a quarter of one  
13 percent, and that goes to a half of one percent next  
14 year.

15 So, we designed it so that there would be some  
16 time for some of these technological developments to  
17 occur.

18 Another thing that we're seeing, the LCFS allows  
19 biofuel producers, and I think John mentioned this, too,  
20 to apply under what we call a method 2a or 2b. These  
21 people, these producers would say you're right, we're  
22 more efficient than what's in the look-up table, they're  
23 allowed to provide a technically compelling case, and  
24 there's been quite a few of them in fact. And a lot of  
25 the Midwest ethanol plants have received a lower carbon

1 intensity than the default value, so they're more  
2 efficient. And I think we're starting to see that, too,  
3 that's some innovation, as well.

4 We're also working on some internal pathways,  
5 including an anaerobic digester. I think Chuck White  
6 mentioned a digester. And we're working on that  
7 pathway, as well.

8 So, again, I think that we're looking at all  
9 types of alternative fuels here.

10 Regarding credits, we won't know how many  
11 credits have been generated until the end of this month,  
12 that's when the first quarter of 2011 reports are due.  
13 At that point we'll be able to see how many credits were  
14 generated, who generated the credits, and where people  
15 are relative to the standard.

16 We're working on a credit tracking and trading  
17 program. Actually, I think we're going to have a short-  
18 term proposal. Long term, I think the long term it's  
19 going to have to be part of our LCFS reporting tool and  
20 we are working right now on an RFP to get a contractor  
21 to provide that module for our reporting tool.

22 In the short term we're looking at something  
23 that's a little bit more manually based, that ARB would  
24 be involved in, that if someone wanted to move credit  
25 from one place to another, that we would be involved in

1 that in the short term.

2 In the long term, we think that the reporting  
3 tool would handle a lot of that automatically.

4 Regarding HCICOs, first of all, you know, we  
5 like to thank Gordon for doing the screening of the  
6 marketable crudes, he does very good work.

7 Also, I would like to thank Gordon for making  
8 the differentiation, earlier today, between a potential  
9 HCICO and a HCICO.

10 As you saw from the pie charts, three-quarters  
11 of the marketable crudes passed the first, simple basic  
12 screening. So, I wouldn't say that I look at it, look  
13 at the glass as being half full, I look at it as being  
14 maybe three-quarters full at this point. And I do think  
15 there's opportunity for other crudes to be designated as  
16 non-HCICO crudes.

17 You know, Gina did mention that, certainly, from  
18 a scientific stand point, Canadian tar sands, one would  
19 easily be convinced that the energy required to produce  
20 that crude oil is different than conventional crude oil.  
21 And since we look at a complete lifecycle analysis when  
22 it comes to the LCFS, we'd be remiss if we did not take  
23 into account the higher carbon footprint of Canadian tar  
24 sands.

25 One of the things that -- well, first of all,

1 California is not the only entity that's concerned with  
2 Canadian tar sands. Europe is, I think there's a global  
3 concern for that. And one of the allowances in the LCFS  
4 is that if carbon capture and sequestration is used for  
5 some of these HCICOs to bring down their carbon  
6 intensity below a certain level, then they end up being  
7 non-HCICOs again.

8           And I know Alberta has been spending a lot of  
9 effort, a lot of time, a lot of research on CCS for  
10 their tar sands crude, and we think this is a positive  
11 movement.

12           As was mentioned today, too, we have a HCICO  
13 Screening Workgroup, and also HCICO's an agenda item for  
14 the advisory panel. So, I would say that we have  
15 several public processes going to address this issue.  
16 And, as you can tell, it's of concern to a lot of folks  
17 and we've been having a quite a few meetings on this  
18 issue, and we will continue to have full public process  
19 on this issue, as well as other issues with the LCFS.

20           Again, I think the fact that three-quarters of  
21 the crudes passed the initial screening, and there's  
22 potential for others, that I don't think the situation  
23 is as dire as Gordon's Death Valley slide would suggest.

24           I would -- Jim Uihlein mentioned the E85 report  
25 he's looking for. I'm going to go back to my office and

1 inquire about where that report is.

2 We are also working on biodiesel and renewable  
3 diesel specs, fuel specs, and we think some of that had  
4 originally been scheduled, or still is scheduled for  
5 all, but the Low Carbon Fuel Standard is certainly  
6 taking up a lot of staff's time.

7 I'd like to close by saying that, you know,  
8 again, I'm glad to get an update on these alternative  
9 fuels. I think that the LCFS certainly invites them.  
10 In fact, I think drives innovation.

11 And we do understand the challenges of meeting  
12 the LCFS and RFS2, and that we are working with  
13 stakeholders in several workgroups and panels to talk  
14 about the LCFS and see about the availability of fuels,  
15 and the cost of the fuels, et cetera.

16 And I think that through our processes and  
17 through processes like this there's plenty of  
18 opportunity for input. So, thank you.

19 MR. OLSON: Thank you, Mike. I know we have a  
20 meeting scheduled with your staff at some point here,  
21 and the Commissioners, individual Commissioners here, in  
22 the near future, just to get a little better  
23 understanding of the Low Carbon Fuel Standard status.

24 And one thing that, and maybe I've lost track of  
25 this, but would be helpful for us is to -- if you have

1 any comments on expectations for drop-in  
2 biohydrocarbons, the so-called long chain bihydrocarbon,  
3 whether you have pathway studies? It's been kind of a  
4 dearth of information for us, for our records here, and  
5 wondered if you had any comments about that?

6 And I have one other question, too.

7 MR. WAUGH: I know there's been some discussion  
8 of butanol but, in general, I don't think we've had a  
9 lot of people come to us with any types of drop-in fuels  
10 like that. We certainly have talked about renewable  
11 diesel.

12 But, again, with the LCFS being performance  
13 based, you know, if someone comes to us and says we've  
14 got a drop-in fuel, we want to consider that -- I mean  
15 we would, certainly. But to my knowledge, there hasn't  
16 been a lot of discussion right now on drop-in fuels.

17 MR. OLSON: Very good. And one other comment,  
18 question is this would be something we're interested in  
19 the future is a better explanation of the interaction of  
20 the Low Carbon Fuel Standard credit process and the  
21 upcoming cap and trade crediting for the 2015 rollout of  
22 that. And maybe there isn't -- that's not really  
23 described at this point, but we're interested in how  
24 that would interact.

25 MR. WAUGH: Yeah, there's been some initial

1 discussion on that and, you know, with regard to credits  
2 for the LCFS, the regulation right now says that the  
3 credits can't be imported into the LCFS. But if you  
4 have excess credits, that you can export them from the  
5 LCFS if that program that you're exporting to accepts  
6 those credits within their own program.

7 I think there are some challenges with cap and  
8 trade, and challenges of LCFS, and in terms of how that  
9 gets rolled in, in 2015. There's been some discussion  
10 but for the most part it's -- we've been so busy working  
11 on the LCFS that we haven't had a detailed discussion on  
12 that interaction, but I think we would be able to  
13 discuss that in the near future.

14 MR. OLSON: Very good, thank you very much.

15 MR. SCHREMP: Any other questions for Mike, in  
16 the audience?

17 All right. Well, thank you very much, Mike.

18 I guess at this time, Tim, I guess I'll open it  
19 up to additional questions or comments from the  
20 audience?

21 MR. OLSON: Yeah, please, open public comment  
22 from any other questions, either in the room or on the  
23 WebEx?

24 THE REPORTER: Can you get to a mike?

25 MR. SCHREMP: I'll go ahead and repeat.

1 THE REPORTER: Okay.

2 (Whereupon a staffer reads a question from  
3 the internet, by Kathy Scales.)

4 MR. SCHREMP: Well, I think the question, I mean  
5 if I could summarize, is that there are different carbon  
6 intensity crude oils in Canada, and that some of the  
7 crude oil carbon intensities are actually not quite as  
8 bad as those of the thermally enhanced oil recovery of  
9 crude oils in California. And so, how can, I guess, not  
10 me justify -- I mean, I guess that's directed -- a  
11 question for Mike, how can there be justification for  
12 this?

13 I hope you've gotten to read the question.

14 MR. WAUGH: Thank you. Well, first of all,  
15 we're not banning any crude, tar sands crude, or  
16 otherwise. I think my point was to bring out that we  
17 have a function in the regulation that would allow CCS  
18 to be used if there was a HCICO, whether it was a HCICO  
19 related because it was thermally enhanced oil recovery,  
20 or bitumen mining, or whatever other types of reasons  
21 why it would be a HCICO, there's a way that you can drop  
22 the HCICO and become a non-HCICO through CCS. And  
23 that's really what was my point.

24 With regard to the basket, I mean when we looked  
25 to see that we need to reduce the carbon intensity of

1 transportation fuels in California by ten percent, one  
2 would have to start with the baseline. And the baseline  
3 is, well, what crudes were the refineries running in  
4 2006, and that was our baseline. So, as we move forward  
5 and look at other crudes, you know, I still think that  
6 there's a possibility a lot more of them will be  
7 designated as non-HCICOs. And once again, we're not  
8 banning any crudes. I'm just saying that the CCS is a  
9 tool, perhaps, to help a HCICO become a non-HCICO.

10 MR. SCHREMP: Thank you, Mike.

11 Jesse, do we have any other questions online?

12 Okay, thank you.

13 So, I'll turn the microphone back over to Tim.

14 MR. OLSON: So, appreciate the comments, the  
15 panel members, the individual comments and presentations  
16 today. This is very valuable for us to have this  
17 information in our record and it definitely influences  
18 what policies are developed here by the Commissioners.

19 And there's some additional time to supply  
20 comments in writing, you said, is it May 23<sup>rd</sup> is the  
21 date?

22 MR. SCHREMP: That's correct, Tim, we'd like to  
23 have comments to the docket, in writing, by the close of  
24 business on May 23<sup>rd</sup>.

25 MR. OLSON: And could you also, Gordon, remind

1 us, we have some other IEPR hearings on transportation-  
2 related things, is it on the forecast results and  
3 findings, is that -- I thought we had something planned  
4 in August or --

5 MR. WENG-GUTIERREZ: Yeah, so I think we have a  
6 plan of August 16<sup>th</sup> for our next workshop, where we will  
7 be talking about our draft document, and that's what  
8 would be in our final document, that would have anything  
9 in it, and should have our forecast, as well as all of  
10 the LCFS, RFS2 post-processing discussions that we  
11 discussed today.

12 MR. OLSON: And, yes?

13 MR. SCHREMP: And I don't want Malachi just to  
14 sort of understate that. As some of you may recall, our  
15 draft document from 2009 did consist of, I think, in  
16 excess of 250 pages, so there's a lot of stuff in there.

17 So, we will endeavor to get that to stakeholders  
18 as far in advance as feasible, understanding it's a lot  
19 of information they need to digest, to be able to come  
20 here and make comment on August 16<sup>th</sup>.

21 But there will also be opportunities to provide  
22 comment after that workshop into the record, once  
23 they've had more time to look at this But we're going  
24 to do our best to get that ahead to people as soon as  
25 possible.

1           MR. OLSON: And Gina Grey, you had another  
2 comment?

3           MS. GREY: Thanks, Tim. It was right on point  
4 to what Gordon just said that we would really appreciate  
5 something maybe a month in advance, like July 16<sup>th</sup> would  
6 be a great target date. Gordon? Because literally  
7 these documents are huge and I know you're saying we've  
8 got time after but, really, it's best if we could look  
9 at them enough in advance, especially we have a trade  
10 association, with many members that take a long time to  
11 look at these things. So, you know, to come to that  
12 workshop with something to say versus just sitting, it  
13 would be great. Thank you.

14          MR. SCHREMP: Yes, so I think the takeaway for  
15 me is that we go back to management and say that that's  
16 achievable with a one- or two-time review time by  
17 management of our document. I think then we can meet  
18 that, so -- but hear you loud and clear, it's a large  
19 piece of information and we do this every two years, and  
20 it's an important element of the overall IEPR, and so we  
21 will do our best to get that to all the stakeholders as  
22 soon as practical.

23          MR. OLSON: And just to also mention that we  
24 are -- reiterate that we are doing some follow up with  
25 the staff after this hearing.

