BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:) Docket No. 09-IEP-1K

Preparation of the 2009 Integrated Energy Policy Report (2009 IEPR)

JOINT COMMITTEE WORKSHOP ON TRANSPORTATION ENERGY DEMAND AND FUEL INFRASTRUCTURE REQUIREMENTS

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

MONDAY, AUGUST 24, 2009

9:00 A.M.

Reported by:
Peter Petty CER**D-493

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

Kristy Chew, His Advisor

James D. Boyd, Vice Chair and Associate Member, IEPR Committee; Presiding Member Transportation and Fuels Committee

Kelly Birkinshaw, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead
Nick Janusch
Malachi Weng-Gutierrez
Gordon Schremp
James Page
Ryan Eggers
Lynette Green

ALSO PRESENT

Presenters

Joe Sparano, Western States Petroleum Association (WSPA)
Joel Velasco, UNICA
Matthew Tobin, Kinder Morgan
Rahul Iyer, Primafuel
Felix Oduyemi, Southern California Edison (SCE)

Public

John Braeutigan, Valero Energy
Michael Redeemer, Community Fuels
Bill Wason, Sustainable Bio-Brazil
Seth Jacobson, Study for Advanced Studies on Terrorism

Via WebEx

I N D E X

P R O C E E D I N G S

AUGUST 24, 2009 9:11 a.m.

COMMISSIONER BYRON: Ms. Korosec?

MS. KOROSEC: Right. We are going to go ahead and get started now. Good morning, everyone. I am Suzanne Korosec and I lead the Unit that produces the Energy Commission's Integrated Energy Policy Report, or IEPR. Welcome to today's Joint Committee Workshop on Transportation Fuel Forecasts and Analyses.

The purpose of today's workshop is to discuss the Energy Commission Staff Draft Transportation Energy Forecasts and get public input on the proposed forecasts and our related policy concerns. The staff will provide an overview of the framework that they used in their analysis and present preliminary findings on expected fuel demand, projections of fuel and crude oil imports, and the need for transmission infrastructure. Our agenda today will begin with a presentation by the staff on Transportation Economic Trends and Projections; next, we will have a staff presentation on the petroleum and fuel demand forecast, followed by a presentation from Western States Petroleum Association. We will then move to a staff presentation on Renewable Fuels, including Standards, Supply and Demand Projections, and Infrastructure, and then we will break for lunch, resume after lunch with presentations by several renewable fuels stakeholders. After that, the Energy Commission staff will present their Petroleum Fuel Import and Pipeline Export Forecasts, followed by the Crude Oil Import Forecasts. And we will use the remaining workshop time to hear public comments on the day's presentations and discussions, and we hope to adjourn shortly before 5:00.

Just a few housekeeping items before I turn it over to the staff to get us started. Restrooms are out in the atrium through the double doors and to your left; there is a snack room on the second floor at the top of the stairs, under the white awning; and if there is an emergency and we need to evacuate the building, please follow the staff out of the building to the park that is diagonal to the building, Roosevelt Park, and wait there for the all clear signal.

Today's workshop is being broadcast through our WebEx Conferencing System, parties need to be aware that we are recording the workshop and we will make the recording available on our Website within a few days of the workshop, and we will also be posting a written transcript once that becomes available, which is about two weeks after the date of the workshop.

For presenters and commenters, please make sure to speak directly into the microphones here at the podium when you come up to speak, or presenters here at this podium, to make sure that the people on WebEx can hear you speak. And during the public comment period today, we will hear first from those in the room, followed by those on the WebEx. For parties in the room who want to make comments, it is very helpful if you can give the Court Reporter your business card when you come up to speak, so we make sure that your name and affiliation are spelled correctly in our transcript. We are also asking parties to submit written comments, and those are due by 5:00 p.m. on September 4th. The information from this workshop is going to feed into the 2009 IEPR, the first draft of which is expected to be released at the end of September in preparation for a hearing on the draft report that is scheduled for October 14th. So with that, I will turn it over to the Dais for opening comments.

COMMISSIONER BYRON: Thank you, Ms. Korosec. Good morning, everyone. Happy Monday morning to you, all of you who got up to be here on a Monday morning at 9:00, thank you very much. I am Commissioner Jeff Byron. I chair the Commission's Integrated Energy Policy Report Committee, and with me is my Co-Chair of that Committee, Commissioner Boyd, Vice Chair Boyd, and all the way to my left is his advisor, Kelly Birkinshaw. We are hopeful that others will be joining us here at the Dais as the morning goes on. And I would like to thank you for being here at this Joint

Committee Workshop, both the IEPR and the Transportation Fuels Committee, of which Commissioner Boyd is the Chair. Is that correct? Yes.

VICE CHAIR BOYD: Transportation and Fuels Committee, but what the heck?

COMMISSIONER BYRON: Yes. So I am going to keep my opening remarks very brief. This is one in a series of IEPR workshops that we have been conducting for the last number of months and I think we are getting near the end of what I refer to as the IEPR Season. A lot of information gathered by this Commission and we will produce before the year is out a policy report for the State of California around all the key energy issues that we face. I am reminded that the Integrated Energy Policy Report is extremely important to document. A lot of people read it, pay attention to it, and also use it to write legislation. Administrations come and go, legislators come and go, but our policy report tends to be the bedrock, or the foundation, for California's energy policy. And it has been an extremely good document, and it is incumbent upon myself and Vice Chair Boyd to keep the quality of that document up.

We are fortunate today, the Transportation Fuels area is not my forte, we have a very full committee today, but we are fortunate in that Commissioner Boyd has been working in this area for a great deal of time, former

Executive Officer for the Air Resources Board, and a Commissioner here at the California Energy Commission now for about seven years. So, Commissioner Boyd, I am going to turn to you and ask if you have any opening remarks for our workshop today.

VICE CHAIR BOYD: Well, thank you for your kind remarks. My welcome and thanks to all of you for being here this morning, early on a Monday morning, as Commissioner Byron indicated. And I guess after this Commission's third four-day work week, three furlough Fridays having now occurred, we get to work all five days this week. So maybe we can get five days' worth of work done in five days instead of in four, like in the past. But in any event, it is a pleasure to be here. I really do look forward to the 2009 Integrated Energy Policy Report in total, but particularly in this area of Transportation Fuels and what have you. It should be a banner year for this subject. The AB 32 and climate change drives everything anybody does, it seems, these days, so that is a major consideration to this agency in carrying out its responsibility in this arena, if not all the energy areas. We, of course, have our State Alternatives Fuel Plan that was provided by AB 1007, a few years back, and we produced that plan for the State of California, which addresses this agency's overriding concerns for climate change, but in particular, energy responsibilities and transportation fuels responsibilities. Energy security, concern for the State of California drives us to pursue energy security through energy diversity, and that plan led to the passage of AB 118, which provided money and provisions to create an investment plan for investing that money in the subject areas of alternative fuels and alternative vehicle technologies to use those fuels, and that has been done, and that process of investing those dollars has begun, and coincidentally and quite positively, perhaps, the nation's economic stimulus program came along at the time we were getting ready to invest our 118 dollars, and so we have made a huge effort to leverage our dollars with federal dollars, hopefully to the benefit of Californians and California companies, and what have you. And also, the activities we carry out -- and I expect the 2009 IEPR, in particular, to address -- is the taking of other goals and objectives, our biofuels plan, part of the overall bioenergy plan nests with our 1007 plan and our 118 dollars, and all of those activities, in turn, cascade up or down to meet AB 32 objectives, and work coincident with the Air Resources Board's efforts on Low Carbon Fuel Standards. So, as I have said for a long time, everything interacts these days, particularly when considering climate change.

I am looking forward to this IEPR and this day, but this IEPR really providing action recommendations to address all these goals and plans that I previously referenced, and therefore look forward to testimony we hear today, written testimony, and then what the staff will do with that in the form of various solid recommendations for how to address the many problems that they have identified in the report, problems I presume we will be hearing about from folks today, and even more so in writing in the future, and problems that, besides just the statement that we have gaps and deficiencies where I feel we are obliged to start making some pretty strong recommendations of how to bridge those gaps, and I think the 2009 IEPR is a premier year and a golden opportunity to do just that. So, with that, I thank you and look forward to today's presentations.

COMMISSIONER BYRON: Thank you, Commissioner. Hopefully the Chairman, Chairman Douglas, who is also on the Transportation Committee, will have an opportunity to join us today and, of course, will probably stop between presentations to give her an opportunity to speak. Ms. Korosec, would you like to go ahead?

MS. KOROSEC: Yes, let's go ahead and get started. Nick?

MR. JANUSCH: Good morning, Commissioners. Good morning to distinguished guests. My name is Nick Janusch. I work in the Fossil Fuels Office and this morning I will be discussing the transportation and economic trends and projections considered for transportation fuel demand forecasts. Our energy demand forecasts for transportation, they cover various sectors in which we use a portfolio of models, and to give credit for where credit is due, I will name the staff in response for each sector. So the light duty vehicle fuel demand forecast, that was done by Malachi Weng-Gutierrez, raise your hand if you want; the transit fuel demand forecast was done by Laura Lawson; the aviation fuel demand forecast, that was done by Bob McBride and Gerald Zipay; the freight fuel demand forecast, that was done by myself, Nick Janusch; and the off-road fuel demand forecast was done by Ryan Eggers.

Here are the topics I will discuss, which will set the stage today for the current economic uncertainties, trends, and projections used and considered in our forecasts. I will begin with the uncertainties. What are the changes in the regulatory environment? For example, the Low Carbon Fuel Standard aims to reduce harmful emissions and the rules are to be fully enforced in 2012, and will require all participants in the transportation fuels market to reduce carbon intensity, measured by the sum of greenhouse gas emissions in all stages of transportation fuel production and consumption. So this will involve different measures, including the greatly increased use in alternatives to conventional petroleum fuel and vehicles.

Also, fuel price volatility, land use, and markets for alternative vehicles and fuels are also some of the uncertainties, what we considered for our forecasts.

Now I will begin discussing information and bid trends of various transportation demand indicators, as well as economic, demographic, and other variables that are used as inputs in our models. And here in this figure, we see historical and forecasted values of California non-farm employment and California gross state product. The projections used here are inputs in our models and the inputs that drive the models. We can see in this graph the impact of recession, see the dips in the red and the blue? And also, according to Economy.com, Gross State Product is projected to return to positive growth by 2010, pending the recession. Also shown here is Gross State Product is expected to outgrow in plant. Now, here, we compare the projections used in the 2007 IEPR to the projections used for the 2009 IEPR; obviously, a lot has changed since 2007. And here the population number, right here on the red and purple, this is from the Department of Finance, is the population direction trend, as you see, nothing has changed. But the orange and green lines, these are from Economy.com, and I will begin with the top, the orange line, which shows the percentage employed, or the employment ratio, and we see a sharp decline in 2009, and moreover, with the green, we see in-plant projections have been lowered, too. So this is a reflection of the current recession.

Now, let's discuss particularly light-duty vehicles. And before I get into that, vehicles are classified by their gross vehicle weight ratings, and all vehicles, 10,000 pounds or less, are classified as light-duty vehicles, while the vehicles that are greater than 10,000 pounds, those are considered medium and heavy-duty vehicles. So here is a great table that shows the light-duty vehicles stocked by fuel type. And this data is from the Department of Motor Vehicles Database, and it shows the amount of registered, operational on-road light-duty vehicles. And we see a large growth in alternative vehicles compared to gasoline vehicles. And we see in the recent years the hybrid population has really taken off. And we also see a large population of flex fuel vehicles, but this population is not indicative of non-gasoline consumption. Feel free to ask questions while I am going through my presentation.

All right, here are the percentage breakdowns of new light-duty vehicles by quarter, from 2004 to 2008, overlaid with the retail price of gasoline. Now, I want to draw your attention to the last few quarters. As retail fuel prices went up, the percentage of new small cars increased significantly after a steady increase over time, and this was all at the expense of the larger vehicles. And this is indicative that consumers are preferring smaller, more fuel efficient cars in response to the higher fuel prices observed in 2008 and previous years.

Now, from light-duty vehicles, we are going to talk about medium and heavy-duty vehicles. And as I described before, medium and heavy-duty vehicles are considered to weigh more than 10,000 pounds, or more, and these vehicles are primarily used in the freight and transit sectors. Here we have the total population and a distribution of medium and heavy-duty vehicles by seven fuel types, diesel, gasoline, electric, hybrids, natural gas which uses CNG or Liquefied Natural Gas, LNG, and another classification which use fuels such as Methanol, Hydrogen, and Butane. In this figure, the percentage of gasoline vehicles decreased from 52 percent in 2000 to 38 percent, while diesel vehicles percentage has been increasing, and they increased from 48 percent in 2000 to 60 percent in 2008, so you see for diesel the blue bars are increasing, and the green have been decreasing. And I mention all these alternatives fuels, but you can barely see them -- where are the alternative fuels? And you see the sliver at the very end, in 2008 the alternative vehicles made up 1.4 percent of the medium and heavy-duty population, with CNG and LNG combined having the largest share at 1 percent; however, many of these natural gas vehicles are registered to the Government, or transit districts, primarily for urban transit use, and so we see that, with medium and heavy-duty trucks with alternative fuels, it is mostly just down by government purchases, rather than private purchases.

Now on to freight. For California, ports play a very important role in the global economy. Many goods are imported into the ports of California, which are Ports of Oakland, Long Beach, and Los Angeles, and they have to be transported by truck or rail, and I will show you that -- in this figure, it is not a report, but this illustrates the importance of California in the global economy. This figure shows total container traits in the entire nation, and it shows the percentage of the Ports of Oakland, Long Beach, and Los Angeles, and we see that there is a steady increase in the amount of million metric tons traded, and so we see this increase over time, and then here in 2008, we see a contraction. This is a reflection of the global economy contracting. And so this is a source of uncertainty, of where exactly is this trend going to go? Is it going to increase? Is it going to level off? Or will it decrease?

Now we are looking at relativity. This table, which shows data from the American Association of Railroads, shows average weekly number of carloads and inter-mobile units, and to the left we see the annual averages, and to the right the weekly numbers for 2009, and you can see to the right, it is significantly less than the annual averages that were observed in prior years. And so we see that the amount of rail activity has decreased significantly since 2006. And so this is also a reflection of the recession and the demand for goods.

Now, on to trucking and trucking activity. This shows the for-hire truck tonnage index, which is indexed to the year 2000, and measures movement of cargo. The rapid increase in diesel fuel prices in 2008 in conjunction with the severe downturn in the economy significantly reduced trucking activity, and you can see this with the deep decline in the last few months.

Now moving right along to transit. Here, we see the recent trends in unlinked transit ridership for California, as reported by the Federal Transit Administration. And you can see, barely, there has been an increase in transit ridership, and this is a reflection of the people responding to higher fuel prices; but more specifically, this is 2008 data, and here is a table from the American Public Transit Association, showing the California cities with the highest transit growth rates, and here Oakland had the top growth for 2008 of 16.1 percent, so this sort of shows that people have shifted more towards transit in response to the high fuel prices observed last year. Now, here is a table of the results from the 2008 California Vehicle Survey. In that table, we see transit use is highest in the San Francisco region, or transit accessibility and population are high, while the rest of the state region is lowest since population density and transit accessibility is low. There are no significant differences observed in miles traveled to work by household size, however, households with two or three persons have the highest rate of transit use. The number of vehicles in a household has a strong relationship with both the vehicles traveled to work and transit use. And vehicle ownership is positively related to the mean miles traveled to work and transit use decreases with increased number of vehicles available to the household.

Finally, to the last factors covered in my presentation, aviation. And airlines, last year, responded to the jet fuel price increases through the reduction of empty seats and number of flights. Also in response to decreased demand, airlines have taken their least fuel efficient aircraft out of service. And to further illustrate this, this graph shows U.S. airline passenger and claimants, and according to the U.S. Bureau of Transportation Statistics, for the first four months of this year, total passenger and claimants were down 9.1 percent compared to the same period in 2008. You can see that with the green line, compared to the red line here. And that concludes my presentation, and if you have any questions, please, here is my contact information and right now I will respond to any questions you may have.

COMMISSIONER BYRON: Commissioner Boyd?

VICE CHAIR BOYD: Thank you, Nick. A couple of observations and perhaps questions embodied. Your slide 8, which is the light-duty vehicles stocked by fuel type shows a tiny bit of growth in diesel light-duty, which although that, as a fraction of the whole population, is almost insignificant, but I note that just with a mild bit of difference because there has been a lot of questions about whether there would be any increased light-duty diesel powered vehicle penetration. It is growing ever so slightly. The more relevant, or the more significant comment -- it may be relevant, too - is flex fuel, and I would only note that, while this population continues to grow, there is virtually no fueling infrastructure in California, particularly, but basically nationwide other than the Midwest, and no indications that there would be much of a growth in fueling infrastructure, although we are obviously going to try to incent that with our 118 program, to some degree. There is another dilemma of all fuel vehicles getting credits for various things for which there just is not a fueling infrastructure and is a policy problem. Your slide 9, which is new vehicles sold by body type, which is indicative of the trend we were seeing as gasoline prices went up, I would only note that the statistics about Cash for Clunkers lately has certainly turned that trend on its head with the people returning to very large-bodied, you know, they traded an SUV in for an SUV, or a truck for a truck, and gasoline being a tad cheaper, people have reversed themselves somewhat, although I guess today is the last day for that program, so maybe we will see the last of that surge. But hopefully they get a tad better gas mileage in the vehicles than have been turned in. Slide 15, which talks about U.S. ports, and how it has leveled off a little bit, do you know if California ports exactly mirror that trend? This is not disaggregated, it is aggregate for the whole country, and I was just wondering if you had access to any information about Oakland and L.A. Long Beach.

MR. JANUSCH: Yeah, we do have access, but I cannot answer.

VICE CHAIR BOYD: But you do have the data. I would be curious to see later on if California is reflecting the trend. It probably is, but it would be interesting to know that as we formulate comments to be included in the IEPR this year. And the last comment is about transit, and it is interesting to see the growth in transit, the growth is for the most part a little higher in areas that have -- well, the Bay Area has got the best access to transit with BART and pretty decent bus service. I am just wondering if, in 2009, with the budget crunches, every government at all levels has seen, and the fair box increases they have had to employ, as well as the reductions in service, and I know it is too early to know, but I will remain curious as to whether transit manages to hang on to any kind of a growth rate or whether, as has historically been the case, it slips back because it gets punished at the fair box by the need to increase the rates to stay somewhat solvent, and that impacts the people who need the service the most. As I said, those are more comments than questions. Thanks for the information, it was quite interesting when I reviewed it.

MR. JANUSCH: Thank you.

COMMISSIONER BYRON: Okay. Thank you, Nick.

MS. KOROSEC: Next, we will hear from Malachi Weng-Gutierrez.

MR. WENG-GUTIERREZ: Good morning, Commissioners, Advisors. My name is Malachi Weng-Gutierrez. I work in the Fuels and Transportation Division, and I will be talking about the transportation fuel demand and historic and forecasted values for California.

I am going to start off with a slide that just shows the historic trend in gasoline demand. Since 1945, or after World War II, we have had a fairly steady increase in gasoline demand. It has on occasion slowed down and we have had declines in demand, those have primarily been paralleled by recessionary periods, and that is what this slide shows, is that we have a long period of growth until we hit a couple of early recessions in the early '70s and the early '80s, and that is where we get these areas of declining demand, but for the most part, we have a fairly steady growth from 1945 to today. I am going to -- the insert here is lined up so that the grey regions, which are the recessionary periods, should correspond with the demand numbers that are represented here in blue. And I know this insert is fairly small, so my next slide is basically that insert, so you can get a better picture. But, again, I just wanted to highlight that the recessionary periods are those periods which lead to declines in demand and generally we have had pretty steady growth. This is, again, the insert from a previous slide, it is basically an index of real taxable sales of personal income per capita, referenced or indexed to 1970, so you can get a sense of where we had peak taxable sales, this only goes up to 2000, but in this time frame, peak taxable sales in 1978 or 1979, and personal income has been growing fairly steadily, but, again, in the recessionary periods, you have a decline of real per capita personal income.

The next slide is going to focus in on that, the last portion of the first slide, so the last couple of years. It is a floating average of the monthly consumption in California, it is from DOE, it is a 12-month floating average, and it shows that there has been a decline, and a pretty substantial decline in the last year and a half, or two and a half years. Of note, what I thought was interesting in this is that the monthly percent change since October of 2007 has been pretty much negative, consistently, every month, except for one month in 2008. So that is pretty significant. I think it is a fairly long trend and it does pre-date the large drop that we had in the economic crisis in the latter part of 2008.

Now I would like to overlay the prices with the demand that we have been seeing. And so that the red and yellow lines here are the actual retail prices, and then the bar chart below is the consumption numbers in millions of gallons per day. On the left, again, is the annual average consumption, and then on the right in green are the 2008-2009 numbers for consumption. And as you will notice, as the fuel price increased for gasoline, there was a decline in the annual average consumption noted by the red bars. In 2008 and 2009, there has been a fairly -- it is much lower -- or, it is lower than the annual average in the previous years. And it is reacting to the price, as well. So you see that, with the increase in price through July of 2008, there is a decline in consumption, and then it pretty much remains that way, although we had a decline in fuel prices in the latter part of 2008. The recovery of demand has not been there, but that primarily may be caused by, again, the economic downturn that we are seeing recently.

So what I want to do is take a look at how gasoline consumption was occurring on a per capita basis. I thought that might be a better representation of how we are consuming transportation energy, and so that is what this is. It is a representation of per capita demand on an annual basis from 2000 to 2008, and it peaked in 2002, and has been fairly steadily declining since then. The axis on the left here is obviously starting at 380, so it is emphasizing the decline, but there is a decline and it amounts to about 8 percent over this period of time. Now, most of that, about 5.8 percent of that, is from the last year, 2007 to 2008, and I anticipate we will continue to see the downward trend this year in consumption. Again, I think when I looked at the per capita number often people talk about for per capita demand, I did not necessarily think that that was representative of actual demand, or how much we were traveling on the road, so I wanted to take a look at, on a per vehicle basis, on a per driver basis, our demand habits in this period of time, how they changed. And that is what this next slide is. If you look at the annual green or teal colored line, there is a downward trend, as well, and this is the annual per vehicle demand number. And it is a fairly decent decline; the thing that made me suspicious about it was that it was not necessarily due to a decline in -- it was due to two things, a decline in consumption, certainly, but there was definitely a growth in vehicles registered in California. And throughout this period, you actually see an increase in the number of vehicles per person in California, which is fairly significant. So it grew from about 1.05 vehicles to about 1.2 vehicles per person in California. So, while it does not sound significant, it does lead to a fairly significant decline here on a per vehicle basis. But I thought maybe a better representation would be how many drivers we have in California, and are they still consuming the same amount of energy that they consumed in the past. And that is what this dark blue number is. And of the three kinds of numbers that I looked at, per vehicle, per capita, and per driver, this is the flattest. It only has about a 2.5 percent drop over this timeframe, whereas -- well, up until 2007 -- whereas the others are dropping, again, as I said, 8 percent and 11.7 percent for the per vehicle demand drop.

VICE CHAIR BOYD: Malachi, before you move on, I have held this question through the last four slides, which are all showing this somewhat downward trend in the various different statistics you used to illustrate this, and we tied it -- well, it has been stated it is tied to perhaps the price of fuel and people's individual demand, but can you just aggregate this in any way to improvements in fuel economy of vehicles? Has there been a recognizable efficiency improvement, i.e., fuel economy improvement, in these vehicles, as well?

MR. WENG-GUTIERREZ: Sure, that is a good question.

VICE CHAIR BOYD: I only ask good questions. Thank you.

MR. WENG-GUTIERREZ: Right. Well, certainly that would be another indication of why this would be dropping, and that potentially is partially influencing it, but, again, because of the timeframe with which the fleet turns over, as Nick's slide that showed the vehicle population, we are seeing increases in alternative fuel vehicles, and certainly hybrid vehicles are coming into the marketplace at a fairly quick pace, but for it to really influence our overall demand, it is going to take a little while for that to occur. So I would have to say that that probably has not led to a significant -- that does not represent a significant portion of the decline that we are seeing. Most of it would be economic.

VICE CHAIR BOYD: Thank you.

MR. WENG-GUTIERREZ: So taking a look at the diesel numbers, very similar to the gasoline number with the overlaid prices, the historic numbers, we are not seeing such a large contrast between the historic demand, which is the annual average, on the left, and then the numbers in 2008 and 2009. Even with the increases in prices for the first four years here that are representative of 2004 through 2007, we are still seeing an increase in demand for diesel, whereas, in gasoline, we saw a decline. And then in 2008 and 2009, these monthly numbers, you are seeing numbers that are certainly lower than historic numbers, but certainly not as drastically lower as was represented in the gasoline numbers. So I think this indicates the responsiveness of diesel demand is not necessarily correlated as well with prices, and I think that is reasonable given that economic, industrial sector, commercial activity, is the primary driver for diesel consumption. So it is not until the 2008, November of 2008 through March of 2009, that you get something that is fairly low in demand. And that really is more a reflection of the downturn in the economy and the impact that it is having on consumption.

And this is just a bar chart of jet fuel, one of the other fuels that we look at. It looks fairly flat here, but certainly in the last, between 2007 and 2008, there was a decline of about 8.9 percent, a fairly significant decline, and again, I think Nick touched on why that is occurring, you know, the economic conditions are such that the commercial airlines are having to put more people in less planes and to try to conserve and try to maintain their business models while prices are so high and the economy is so bad. I think that is a reasonable trend. The interesting thing will be to see whether or not it continues. And I will get to that in the forecast numbers.

COMMISSIONER BYRON: Excuse me.

MR. WENG-GUTIERREZ: Sure.

COMMISSIONER BYRON: Mr. Gutierrez, I -- this is a lack of knowledge on my part, I think, when I ask a question like this, but of course, this is California commercial jet fuel, and if costs are higher, of course, because of the mobility of jet aircraft, could there also be declines as a result of now taking on fuel in other states? Would we be able to pick that sort of thing up?

MR. WENG-GUTIERREZ: I think they could make that choice. I do not know if there is a large variability on the price of jet fuel across the states, but that could certainly influence the numbers, and that would be true of, say, freight, as well, and anything where you have crossstate travel, if prices are lower in other states, it could potentially influence it. Gordon, did you have a comment?

MR. SCHREMP: Yeah, Gordon Schremp, Energy Commission staff. I just wanted to add to that, that airlines in their fueling behavior usually load enough fuel to make the destination with an additional amount of fuel for loitering time in the area. On rare occasions, you will see an airport that may be without adequate supply of fuel, like McCarron Airport in Las Vegas, and a plane will fly in with enough fuel to get to Las Vegas, and then continue on to Phoenix, but that is very rare. Airlines are usually fueling in a safe manner at each point to get to the next leg in their destination, and so we do not really see these kinds of over-fueling or under-fueling in response to differences in price; but, as Malachi points out, if you look at the regional price differences in jet fuel, they are remarkably similar. It is a very fungible commodity in the United States and globally.

COMMISSIONER BYRON: Thank you.

MR. WENG-GUTIERREZ: So now I am going to discuss the models and urgently discuss the models, really, just to show these -- discuss these points. Really, what I want to focus in on is the CalCARS model, or the light-duty demand forecast and the methods used for that forecast. As in previous forecasts, we base our forecasts on the economic models. For the light-duty sector, we have in the past used CalCARS and this time around we used a modified low demand case modified by the current economic conditions. For freight, we used the freight model, which Nick is the one who operates, and we updated that with all the economic growth indicators for the industrial sectors that we evaluate. For trends that we updated with new economic and demographic information, as well as inserting additional trends and agency information, we go out with a survey to collect data from trends agencies in California. We use all of that information to then model transit demand to California. And probably the one model that was changed most significantly was the aviation model, this time around, it basically got a new specification, as well as getting updated with the economic and demographic data that we used for the forecast.

So what I am going to present in the coming slides will be a draft version of our gasoline demand. What I want to highlight is the light-duty gasoline and diesel forecast method. For 2007 and 2008, we basically used historic sales numbers, so those are actual numbers that we used from DOE, adjusting for certain -- we had to adjust for certain audits and things like that. So we are pretty comfortable with those numbers, those are actual. In 2009, what we did was we used two sets of numbers for our high and our low demand case. And what we did was we used an estimate of decline from a 2008 number as the basis of our 2009 number, and so, for the high case, we used the 12-month average drop, and then for our low demand case, we used the current year percent drop in demand. So for gasoline, we had, say, four months of actual data from DOE, that decline was four and a half percent, and that was what we used, then, as our starting point for the 2009 number for the low demand case. I do not know if that makes sense, but basically we used two different projections of decline from 2008 as the starting point for our 2009 number -- for our two different cases. So we came up with those numbers, the high and low demand case numbers, based on these declines, and then what we did was we used the annual average growth rates that were defined in the 2007 low demand case to pivot off of those numbers, so basically we used the growth rates from that 2007 low demand case, and grew from the two points that we had defined for 2009. And we chose that number, or that demand case, because we felt it best represented the current prices, as well as the current policy case -- policy environment -- today. So that was the starting point for the 2010 through 2030 numbers. That allowed us to develop a reference case, which I will show you. This is a reference case that was developed using that method, and then we decided what we wanted to do was represent a band of possible demand around this reference case. And so, for the gasoline forecast, we used a 15 percent band around this reference case, phased in over eight years, and that is what this final slide is. So if you see here that the dash line is the reference case, which is what I described, the starting point being at that calculated number, and then the annual growth rate from the 2007 number is what defines the shape of that, and then we use this 15 percent variation around that band, phased in over that eight-year period, to get the two demand cases, the high and the low. And these are the numbers that resulted from that analysis. And they are fairly significant. The low demand case, there is a drop of about 33 percent in demand, and that is very significant. And I think the thing that is interesting about these two numbers, or the two series of numbers, is that, in the early part of the low demand case, you are getting fairly significant drops. So by 2015, or in 2015, you have this 13.25 percent drop in demand, whereas in the high demand case, you are actually getting a growth, so again, that could potentially be attributed to policies such as Pavley, Pavley 2, other things in the short term influencing these demand numbers, continued high unemployment, certainly for the long-term, I think we are seeing that employment is going to be an issue in California. We will probably have higher unemployment than we have in not the recent past, but in the early part of 2001-2002 timeframe. We had fairly decent unemployment. I think the forecast that we are looking at is anticipating higher unemployment in that timeframe. So again, I think the interesting thing here is the short-term differences. The long-term numbers are fairly similar in their growth rates. And just also, the high number here is just -- is about a 10 percent drop. So high demand case, 10 percent drop; low demand case, 33 percent drop.

So what I shared before was just the light duty portion and this is the total demand number aggregating the medium and heavy duty demands, as well. And it does not change that significantly, but it does get bumped up slightly. The shapes are fairly similar to what was -- most demand is light-duty. So adding the medium and heavy duty gasoline demand does not significantly change those demands, but it does raise it slightly. So the thing that I wanted to emphasize on this slide is that these numbers are the starting point for our analysis of the renewable fuel standards, so these do not reflect compliance with RFS 2, and do not necessarily reflect a lower demand which would occur if we were to comply with RFS, which would mean that we would have higher E85 numbers, that E85 would draw from these gasoline numbers, and so our demand number for gasoline would actually be lower than this -- in the case where we are complying with RFS.

VICE CHAIR BOYD: Malachi, you referenced, of course, the national RFS. What about any California goals, objectives, and targets such as, well, have you attempted to take into account what the Low Carbon Fuel Standard might do? Have you included the biofuels targets that California has set up for itself and our demands for electricity and transportation fuel, electric cars, etc., so on and so forth? Is that already factored into this?

MR. WENG-GUTIERREZ: Not explicitly. Again, I followed the method, as I described, to come up with these forecasts. It does not really take into consideration a competitive alternative fuels market. That would be something that we have done with the CalCARS model, had we been able to do that. It would have shown how those alternatives fuels would compete in the marketplace, and what fraction of the transportation would be taken up by those. And with LCSF, again, it is not really included in this. I would say that Pavley is, Pavley 1 is included in these numbers. Pavley 2 may be included in them, but we did not specifically include them.

VICE CHAIR BOYD: It does not really exist yet, right?

MR. WENG-GUTIERREZ: Right, well, but that is true. I mean, there is talk of Pavley 3 and on and on and on. But even so, you know, we did not model, say, the EISA 2007 fuel economy standard impact to demand. What we did was we followed a method that I described, but we did not insert, say, 35 mile per gallon by 2020 and see what the demand ended up looking like, that was not something that we did with these numbers.

VICE CHAIR BOYD: Thank you.

MR. WENG-GUTIERREZ: But there certainly are -- I mean, given that this is a 33 percent drop in gasoline demand, there have to be things that are influencing that drop. I would anticipate things like, you know, LCSF, the ZEV mandate, you know, Pavley 2 and up and beyond, you know, carbon cap and trade, other -- AB 118 activities, AB 32 activities, would contribute to the decline in gasoline demand, certainly in the low case. So -- but again, I think what we were trying to do here is represent a band of possible demand numbers, and I think that we are certainly -- we would like comments on this to get a sense of if there are things we need to include further, or if there are certain things we have overlooked in this analysis. And then, similarly, things like land use, smart land growth, and things like that, we have not explicitly included those. They could contribute to the decline that we are seeing in this low demand case.

So these are the numbers for the overall demand for gasoline. And, again, they are very similar to the light-duty numbers, primarily because light-duty is most of the market. But 33.5 percent hereon for the low demand case, and a 10.4 percent drop over the 2007 to 2030 timeframe for the high demand case.

Now, this slide -- there have been a lot of discussions internally about, well, the forecasts we were putting together, and we wanted to contrast it with another forecast that was out there, so we took a look at the EIA demand forecasts and compared it with ours, and that is what this is. And so the green numbers, or the teal numbers, are the EIA numbers, and then the yellow, which I am hoping is showing up appropriately here, are our numbers. And if you notice, the high demand case for the Energy Commission is falling between EIA's high and reference case, and the numbers at the end here are the prices of the fuels, so this is 213 cents per gallon in 2030, so it does make sense that we would have a demand number that would fall between these two numbers. Similarly, our reference case falls just below their reference case. Again, that seems reasonable. And then our final number, the low demand case, falls below their low demand case. Now, although the prices here are different, so that their low demand case has a fairly higher price for fuel there, I think the regulatory and policy conditions in California are certainly different than the national policy conditions. So there are many things in California that are pushing our demand probably lower than what we would see in the national arena. Now, you know, if other states adopt our policies, then maybe that would not be true. Or, I could not say that, but I think that, for the time being, it seems reasonable that we would have a lower number than what might be observed in the national arena.

So I am just going to proceed to the numbers associated with the diesel demand. These are the numbers presented in the report, again, short-term declines in demand primarily due to economic conditions; in the long-term, we see a return to growth as the economy recovers and consumption begins to increase again. So goods movement is one of the primary drivers here, and that is what we see as recovering over the time frame of the forecast. In the low demand case, we see about a seven percent increase in demand, and then in the high demand case, we are seeing about a 16.1 percent growth in demand. And this is a representation of those numbers. Now, if you notice, there is kind of a flat portion here, a flat period of 2015 to 2016, not quite sure what that is, but I think it has -- it is referencing a number of the commodities that we have as input. So there is a forecast, I looked at the two different forecasts for transit and freight, and both have a time period where there is a flattening of their demand. Now, for transit, you do not see it significantly here because, again, freight is the primary driver for that diesel demand, but it does flatten out, as well. And it flattens out a little bit later in this forecast. But the 2015-2016 flattening, I think, is primarily due to certain commodities and their growth projections. Basically, those are the inputs to the freight model, and that is what would be causing that.

Finally, for jet fuel, we are seeing a substantial growth in jet fuel, again, a recovery of the short term downturn. We are thinking that demand for jet fuel is going to increase fairly significantly. Over the forecast period, jet fuel is increasing by 48 percent in the low demand case, and upwards of 66 percent for the high demand case. And, again, that is projecting a fairly healthy growth in that sector. And there is a graph of the band around the jet fuel demand. Now, these jet fuel numbers do not include military demand, I believe, so there might be some contribution to that, but for the most part, this is the Jet Fuel A, which is a jet fuel that we are forecasting. So, with that, if there are any questions, I would be happy to address them. More comments or suggestions?

COMMISSIONER BYRON: No. Thank you very much. Good presentation. I think we will press on.

MR. WENG-GUTIERREZ: Okay, great.

MS. KOROSEC: Next, we will hear from Mr. Sparano from Western States Petroleum Association.

COMMISSIONER BYRON: Mr. Sparano, I have not seen you for a while and I know you do not believe me when I say this, but I am always glad to see you and hear from you. I always learn from you when you come present before this Commission.

MR. SPARANO: Good morning, Commissioners, CEC staff, and members of the audience. Very kind of you, Commissioner Byron. I always enjoy being here, too, particularly at the times where I am humbled into remembering who I am and where I came from, which happens often here, but today I might surprise you a little bit. Let me state for the record, I am Joe Sparano. I am President of the Western States Petroleum Association. I want to share WSPA's views on this report with you today. I have an overall observation, and that is I would like to commend, compliment the CEC staff on a job well done. I think you have prepared a credible and thorough forecast of the state's transportation fuel requirements.

VICE CHAIR BOYD: Excuse me. Did I hear you correctly?

MR. SPARANO: Someone out there, someone, somewhere, will beep me up for having said that, but you know what? Fair is fair. And so I think it is important --

VICE CHAIR BOYD: I wanted to make sure I heard that correctly. Staff, you got compliments. Remember that.

MR. SPARANO: I have had less hard times when I have not complimented the staff, so I may have to re-think this.

I think the report does a really good job of identifying many infrastructure, fuel, and supply chain uncertainties and challenges that WSPA has, I hope, tried to identify for you over the many years we have been working together on IEPR's. We think that, although the report contains some estimates on declining gasoline use that we feel are overstated, so first response from the public to what the two Commissioners were asking about in the two previous presentations. I think the report does acknowledge the important role that petroleum is going to play far out into the future in California.

We had some basic messages back in April when I stood here and I think they are pretty much unchanged, and worth repeating. We are going to need all the fossil fuels that we can get to meet U.S. and California energy demand far into the future. Infrastructure capacity for liquid fuels remains a capacity and will require expansion to meet future demand. There is very little infrastructure in place right now for alternative and renewable fuels and it will be those elements of infrastructure that will be required to bring in, as yet, not commercialized renewable and alternative fuels to California market. The future is going to require multiple sources of energy supplies to meet demand, and that would include expanded access to off-shore California and federal energy resources. And, finally, the question remains, who is going to develop and pay for all of the investments necessary to bring those renewable and alternative fuels to market, for example, the low carbon fuels mandated by the LCFS regulation that was adopted in April 2009.

I do have a recommendation that I want to share before going on, and that is WSPA recommends that staff in each ensuing IEPR go back to the previous IEPR forecast of demand, supply, and future development, and analyze how accurate prior analyses were, so that the quality of each future IEPR would be enhanced and improved, and at least informed by that check of what has been forecasted previously.

I love this artwork. I am not sure if it makes any sense at all with respect to what we are talking about, but I like it, so it is here. For those of you who do not know, this is *The Scream*, by Edvard Munch, and it illustrates, I think, a key issue in the energy policy debate, and while many have postulated that the world is running out of oil, and quickly, I think that is a notion that has been asserted four or five times this century and, in every case, technology improvements have been the equalizer. And our industry has worked hard and been successful around the world in finding and producing more and more oil. So there are lots of opinions and lots of facts that surround this issue, but I think we are not running out of oil any time soon. But the notion of the end of oil, or peak oil, I think, has helped drive policy that calls for the reduction, or even elimination, of petroleum. And we think more balanced policy initiatives are required and would serve all of us better.

We have expressed some core concerns that we think are now reflected in the staff report. They include the issue with the existing petroleum infrastructure that it is constrained in capacity, and that presents a real and present danger to a reliable and stable future supply of transportation fuels. There is a lack of attention, we think, being given to the complex intersection of the federal RFS 2 mandate, as well as the LCFS and other programs. This is a very complicated area, as I think was evidenced by a couple of the questions that were already asked in the first two staff reports. And California has had and delivered for a long time on its desire to show leadership in the area of climate change policies, in fostering an environment in which hope and optimism, unfortunately, in our view, are replacing realism and sound energy policy. So that is something to look out for. For example, as to forecast document notes, policies dictating renewable fuel usage are not aligned with the availability of those fuels, the vehicles in place to use them, or the infrastructure necessary to deliver those fuels to market. And 22 years from now, or 21 years from now in 2030, that may work itself out, but right now I do not see any specific policies, and certainly no hardware in the ground that would make me feel more comfortable about that situation.

We do agree with the report's observations about the lack of integration of fuel with vehicles and consumer elements of the transportation equation, and that is something that is going to have to be solved. In addition, we are concerned about the newly adopted LCFS, which will require compliance with a program that is not achievable with today's technology and fuel portfolio, and that will require extremely costly innovation. It is not something we can just wave our hands at. It is ironic, additionally, that the LCFS may have the unintended consequence of advantaging non-domestic fuels, like Brazilian sugar-based Ethanol, rather than domestic fuels to replace non-domestic crude oil and other fuels. I think what we are all looking for is some opportunity to have more and more domestic fuel supplies enter our fuel supply portfolio.

Finally, on this slide, we are particularly gratified that the Energy Commission has recognized the wealth of opportunities California has to improve our energy supply security by expanding the development of oil and natural gas reserves off the California coast. Let's look quickly at some specific U.S. domestic energy supply issues. I have used this slide before, I will not spend a lot of time on it, it shows very clearly the vast amount of oil and natural gas described as undiscovered technically recoverable, and that means with today's technology, crude oil and natural gas off both coasts in the Gulf of Mexico and on and offshore in Alaska. Looking just at the Pacific offshore, which clearly is of greatest interest to California citizens and consumers and policymakers, that is a 20-year-old estimate. On the one hand, it is probably better than a lot of areas because we have been drilling out there for over 40 years, drilling has continued right up through today, pretty abundant offshore operation producing around 100,000 barrels a day of our 650,000 barrels a day California production. But those numbers, 10.5 billion barrels of oil, 18 trillion cubic feet of natural gas, the equivalent is two to three more billion barrels of oil, the oil by itself, if we could produce it at the same rate as today's foreign imports, which at the end of 2008, the CEC identified as about 850,000 barrels a day, or 48.5 percent of all the crude we put in California refineries, if we could produce that offshore resource at the same rate, we could eliminate foreign imports for over 30 years. Now, no one is saying today that we can run and produce at that rate. It will certainly take time if we are allowed to drill offshore to ramp up, but I think the figures are illustrative of great opportunity that sits there offshore. And if you are looking at issues about the end of oil, there is even more vast quantities of oil in Canada, and around the world, according to lots of sources. But right now, we should be concerned about policies that affect our situation and, in particular, the offshore supplies off the coast of California.

The MMS has been very vocal and straightforward, Minerals Management Service of the Department of Interior, in describing the record of this industry in its activity offshore, and certainly there is a lot of interest, a lot of emotion that surrounds offshore California drilling, almost all of it precipitated by the tragic and terrible spill in 1969 in the Santa Barbara Channel. Since then, in 40 years, the industry has produced a billion barrels of oil offshore California, spilled 850 barrels that you can see, according to this report. I can assure you that it is 850 barrels too many. I have been in this industry 40 years and I know how I feel, and how my associates feel. We all get up every day with a target of no spills anywhere -- ever. It is a daunting challenge to meet that objective, but that is where it starts, and I think this record, as shown by the MMS, illustrates that there has been a good degree of success in this area. I think bringing these offshore resources to market will have a beneficial effect on consumers and businesses. It will provide much needed long-term stability to transportation fuel markets. I mentioned earlier, California currently imports almost 50 percent of the oil we use to make products from foreign sources. We import another 13 percent, according to this agency, from Alaska. Sixty-two percent of everything we use shows up here by tanker. And that is a number that is only going to get bigger as California production decline continues. And so we need to augment existing production.

There are some other benefits that accrue from additional offshore drilling, the numbers that I am going to give you next are from a study by ICF International about the MMS five-year plan that is currently under evaluation by the Department of Interior. These numbers relate specifically to California, they relate to the 2030 timeframe. The benefits of accessing offshore resources include more than 14,000 new jobs in California, $3 billion estimated new economic output, and over $12 billion in new government revenue, and that is for state and local, county, city revenue needs and needs to fund services. And those are real dollars, they are not new taxes. They are dollars that accrue from the act of producing and the revenue sharing the rents that are paid on leases, the bid bonuses, and then the ongoing revenues from royalties, as these barrels are produced.

Let's take a look at some of the technology involved here. This is a quick picture of what is called Extended Reach Drilling. Extended Reach Drilling has already been proven worldwide and even in California in some areas to be useful, and safe, and environmentally sensitive out to anywhere between three and seven miles from the drill site. Why is this important? Well, if you want to drill offshore California, there are some areas where you can site a drill operation on land and drill out into the reservoir. That is what this picture shows. And it is an important facet of our technology improvement that I think is critical for California policymakers and consumers, citizens, to understand.

While we are on this slide, I want to just depart a second and talk about some specific issues with the IEPR document, and they relate directly to the questions that Commissioner Byron and Commissioner Boyd were asking during the staff presentations. You have a very very strong reduction in gasoline consumption, I think more than 33 percent by 2030. The State Department of Finance has identified that our population is likely to grow during the same timeframe by more than 30 percent from 37 million citizens now to close to 50 million by 2030. And looking at the low demand scenario, that implies, calculates out to, but I guess "implies" is still a fair word, a per capita drop from over 400 gallons per capita down to about 200 gallons per capita. It just seems to us like an awful lot and maybe an area you want to go back and take another look at how credible that may be. That is a lot less driving for a lot more people. So I think it is something that requires further examination.

Here is another look at technology and this happens to be Extended Reach Drilling that starts on an existing offshore platform, or it could be a new one, but in California's case, we have 27 platforms currently in operation off the coast, 22 in federal waters, five in state waters, we have five drilling islands. Certainly, the platforms that are operating today present an opportunity, if and when the MMS five-year plan is approved, to reach from those existing platforms, either back into state waters, or out into federal waters where there is considerably more oil and gas, at least by the MMS estimates.

I mentioned earlier that we are encouraged by the report's recognition of the potential for developing California's offshore resources. I want to quote the report on page 21 because there are a couple observations I have about this next statement. The report says, "The continued decline of California crude oil production could be reversed through increase exploration and drilling in state and federal waters, but any appreciable impact on the level of imported oil would be at least a decade away." Well, we do not claim that our abundant offshore energy resources can be produced overnight, however, as I have said on many occasions before, California is probably in the unique position versus the rest of the country to bring those resources that exist offshore and which we are not currently allowed to access, bring those to market a lot faster than many other areas. There are several projects already awaiting approval, review and approval, that could bring offshore California oil online and to market way before the ten-year time period indicated in the report, and help us reduce our dependence on imports. The staff report also states that expanded offshore development would require, and I will quote, "new infrastructure of offshore oil production platforms, interconnecting pipelines, crude oil trunk lines, and pump stations." Several of the offshore and onshore projects that have been proposed will utilize existing infrastructure along with advanced technology and state-of-the-art techniques, such as Extended Reach Drilling. That will allow us to access new oil and gas supplies and bring them to market safety and with environmental sensitivity long before 10 years are out, and with, in many cases, existing infrastructure. That is not to say that, if we are allowed offshore, and we have a lot more opportunity, that there would not be some new platforms and more lines, trunk lines, and facilities onshore. I do not know that at this point. But we certainly have the means with existing facilities to do a lot of producing in a timeframe that is measured in a couple of years or more, rather than a decade or more, and that can only help us with respect to our current high amount of foreign imports, and we become more and more vulnerable every day as those imports increase.

This is another unusual cartoon, again, I like it, so we use it from time to time, and it reflects the notion that all we have to do to get rid of our addiction to oil is just move to alternative and renewable energy, and that will be accomplished relatively easily. And I think renewable energy supplies, even with huge huge projected growth rates in the EIA forecasts that were mentioned earlier, are going to take decades before they gain substantial market share, and the EIA in a chart that I will show you in a minute, paints a very different picture than just switching from oil to all kinds of renewables, and being happily on our way into a different future. That may in fact be our future many years out. But it is not around the corner and I think there is an element of realism that we have to inject into our policy debates. EIA has already reduced their forecast twice this year, their annual energy outlook. But still, it anticipates nothing like the drop in demand for gasoline that is suggested in the staff report. The EIA report shows that, despite huge increases in biomass and other renewables between 2007 and 2030, by 2030, fossil fuels, oil and gas, and coal, will still make up 78 percent of the supplies to meet forecasted demand, 22 percent for biomass and renewables, plus nuclear, plus hydro. And I will show you that on the next slide. But just one more point here about alternative energy. Whether there are additional imports of foreign energy supplies, or other U.S. crudes, or whether there are new renewable and alternative fuels that are developed consistent with this plan and with other state plans, all of those new fuels will require infrastructure. Right now, we can get Ethanol here by rail car, we can get it here by barge, and a lot of good work in the staff report identifying some of the challenges that may occur if those Ethanol delivery systems no longer will carry the corn-based Ethanol, rather other types of Ethanol -- cellulosic, Brazilian Ethanol based on sugarcane, they may require some dramatically different applications and certainly more hardware on the ground. So that is going to take more permitting, it is going to face the same permitting and community challenges that conventional energy has faced, and it is still going to need huge amounts of investment capital. So those are some things I would like the staff and the Commission to think of as you go forward.

This is the EIA chart. I will not spend much time on it, but look on the right-hand side, your right, my right, that is the breakdown, still 55 percent oil and gas, almost 11 percent from biomass and renewables, it is a huge 105 percent growth from the 2007 amount of those fuels, but still 11 percent of the total. Nuclear is flat, hydro is flat, altogether they make up about 22 percent. So I call on this when I use it in other areas just for a reality check. This is a hard reality from EIA. And, as I have said, they have already trimmed this forecast twice to reflect economic downturn and changes in demand that have occurred this year for petroleum and other products.

I have used this chart before and I will not spend a lot of time on it. The main point here is, in our existing system there are no pipelines that bring crude or products into California, none. You can see where the major refining centers are in this country, mostly in the Gulf

Coast, but also here in California and in Washington, replacing supplies that are missing for whatever reason is an arduous task and can require 10-40 days, depending on where you have to get that supply. There is no reason to think that infrastructure for renewable fuels and alternatives will face any less daunting challenge, and many of the renewables that are looked at today as fuels of the future that will replace or augment petroleum still have to start their long trip to have infrastructure in place in California that will satisfy our needs and carry the volume of fuels that are going to be necessary to make a market penetration into California's fuel supply portfolio.

What does that all mean? Well, a lot of people last year carried the mantra of "Drill, Baby, Drill," since I have been here in Sacramento, I have heard the opposite many times, which is don’t drill anywhere or building anything -- ever -- if it happens to be petroleum-based. And I think those are two extremes and we will be well-served by finding ourselves and putting ourselves through policy decisions somewhere closer to the middle of that. And even though demand has dropped, we still do not have very good energy security in California. I mentioned the numbers in the U.S. and we are already at 60-65 percent of foreign imports for every single drop of crude and products we use in America every day -- 60-65 percent, it is not getting better. It will only get better through the combination of more domestic supplies and alternatives and renewables working their way into the marketplace.

So what do we do? We think the policy options include some balance, certainly additional domestic supplies through greater access, conserving energy, we all can do that every day with how we use energy as individuals, better efficiency, industry has an obligation and an opportunity from an economic standpoint to do a better job of being more efficient in how we operate, and finally, developing alternative and renewable fuels and technologies of all sorts. The next generation Ethanol, biodiesel, other biomass fuels, solar, wind, hydrogen, electric battery design. And then we should not forget nuclear applications that create clean products from coal and oil sands in Canada, and oil shale in the United States, both of those last two have incredibly large volumes of reserves that are available to come to market. They certainly each have their technical challenges and greenhouse gas issues, but everyone who is involved in both of those activities is sensitive to and understands the need and requirement to deal with those issues. And we certainly have an opportunity to create more domestic supplies if we are able to bring those to market.

I have shown you this slide before. This is the last one. Our industry, not surprisingly, thinks the path to success starts with the existing cleaner burning supply of petroleum. We have made it cleaner year after year and will continue to do so. It certainly can and should be augmented by all types of renewables and alternative fuels, scientifically sound -- they have to work -- technologically feasible, you have to be able to deliver them to market in commercial quantities. It is one thing to drive a car from North America to the tip of South America, as one fellow did a couple years ago, and stopped at every McDonald's and other fast food place, and take French fry oil and put it in the tank, and power the car -- that is doable, it is just not doable on a mass scale. So we have to get there, and things have to be cost-effective. So balanced supply is the key. And I think the more we concentrate on that, the better off we will be.

So let me make a few closing comments. We encourage the Commission to continue to identify the benefits to California for increased access to energy resources, particularly those on California's outer Continental Shelf. In many respects, the only thing that stands in the way of improved energy security for California is an outdated political Orthodoxy. There is a lot of politics in the area of offshore access. We think it is time to re-think our policies and our politics with respect to offshore access, and to bring what is truly a vast amount of technically recoverable energy supplies off our coast into California's energy supply portfolio. California citizens and consumers who are currently hurting from high unemployment and reduced services would be the beneficiaries of more jobs, new revenues for state and local governments, and greater energy supply security. Thank you for giving me the opportunity to share WSPA's views with you this morning. I would be happy to answer your questions.

VICE CHAIR BOYD: Well, thank you, Joe. You are right, there was enlightenment in the presentation. Just a comment, it is almost not a question. One of the dilemmas with potential continued reliance on petroleum is, of course, it is a fossil fuel, which you acknowledge, and the global climate change concerns and programs do put pressure on petroleum. The Low Carbon Fuel Standard proposal of the state is not a proposal, as I understand it, to eliminate petroleum, rather it recognizes that petroleum will be used in the future. It appears to be an effort, you know, just to reduce the carbon footprint of that petroleum. So reduce, but maybe not eliminate, is something I see in the many goals of California government. And the other thing that you reference, too, is energy security, I mean, that in eliminating foreign imports. You put all of those things together and, as you acknowledge, there will be a role for alternatives and these are the competing fuels that we have to deal with. So I think you commendably recognize conservation efficiency and the development of alternatives, and I think actions the state is taking do acknowledge that, like it or not, petroleum is going to be the dominant transportation fuel for a long long time, for lots of the reasons you indicate. But I do not see in some of us, you know, a political desire to eliminate petroleum or even that which is the reduction component, it is to address these other issues. Fossil, you know, any fossil fuels are problematic with regard to greenhouse gas issues, climate change, and what have you, and that is what drives us to a very large degree these days, so I see the paths melding better than they have before. We still have our somewhat different views on how fast we have to go places, but I did not really have a question, it is more a statement, per usual.

MR. SPARANO: Commissioner Boyd, thank you for the statement. Certainly, the issue of greenhouse gas is one which concerns us as an industry, as it does the rest of California, the nation, and the world. One of the things that we do believe will be very beneficial, I did not mention it in the context of the discussion, but I will in response to your observations. Carbon capture and sequestration, or carbon capture and storage, is a really important element that we need to ensure that policymakers understand. This has been used for 50 years or so in this industry, largely outside of California, but it presents a great opportunity to use the carbon dioxide produced in whatever situation, and put it down hole into an existing petroleum operation, and help with enhanced oil recovery to move out more oil from a reservoir, or simply stick it in a reservoir that has been depleted, where it will stay for eons. So that is one piece of the puzzle. The other I want to mention, I think it cannot be understated, the Low Carbon Fuel Standard, for all of its well intended policy objectives, we are sitting today faced with a dilemma as an industry of having no known pathways to beat the Low Carbon Fuel Standard requirements, and, yes, it has been back-end loaded, which is very fortunate for all of us, but there are still lots of dilemmas and one that is very very important, that people should understand, gasoline has a carbon intensity of 96, corn-based Ethanol, according to many, and I guess the important thing, according to the Air Resources Board, when you use a full lifecycle analysis, it has a carbon intensity of 96 and change. We are not going to be able to use corn-based Ethanol to meet our 10 percent reduction in intensity. Cellulosic Ethanol, as far as I know, not only are there no plants operational, but there are not any with steel in the ground because the process still has not reached commercial availability. So those are the kind of things that are going to challenge all of us to try and meet these laudable objectives, and I just wanted to mention those two since you gave me the opportunity.

VICE CHAIR BOYD: Well, just one last comment. You hit the nail on the head, and I neglected to mention lifecycle analysis, but that is going to be the decider for many many things in the future, and whether or not that gives advantages to the likes of Brazilian Ethanol versus corn, or other alternatives, it will all come out in that equation once those equations are thoroughly developed, and that will give us our answers to a very large degree.

COMMISSIONER BYRON: Mr. Sparano, thank you. I am glad you like certain aspects of the report. I wanted to drill down on one of them a little bit more, that being the staff conclusion that oil production could be reversed through increased exploration and drilling. Do you agree with the staff's numbers in the report with regard to the number of barrels per day that could be increased with offshore drilling?

MR. SPARANO: I do not know how to -- I have read the numbers, I went through the report, the 28,000 or so at the start from one project, 28,000 barrels a day, and I think it was all the way up to 430 or 450,000 barrels a day by 2030. Did I get that right?

COMMISSIONER BYRON: 480,000 barrels.

MR. SPARANO: 480,000 -- that is more than half our current imports. I do not have the knowledge of how you arrived at those numbers, but I think perhaps more importantly than whether I agree with them or not, is how substantial they are, and our ability through technology and through the existing infrastructure to bring more of those production barrels to market earlier will be key to helping our energy security.

COMMISSIONER BYRON: It also stated in the report that that would be about 10 years to get to -- well, let's see if I --

MR. SPARANO: It said it could be a decade before we see any of the production, and my observation was that there are three or four projects already in place, ready to go, that would bring more than a few 10,000 barrels a day to market within a short period of time if and when we got approval to access the reservoirs.

COMMISSIONER BYRON: Right. The report talks about these having a personal impact would be at least a decade away, and you indicated in your comments that there were opportunities with minimal or no new infrastructure, including possibly no new offshore oil production platforms, pipelines, or trunk lines. So my question is, so you are suggesting that we would be using existing infrastructure to get access to some of these early opportunities?

MR. SPARANO: Right. There is a project that everyone knows about because it is in the budget, called "Tranquillon Ridge" that proposes to drill from an existing operational platform in federal waters, back into state reservoir, to bring oil to market through the existing platform under sea line and oil processing plant. There is a competing project onshore at Vandenberg Air Force Base that would use the same Extended Reach Drilling technology to accomplish the same goal. There is a third project called "Paradon Project" by another of our members, three different ones, that would produce from an existing platform in state waters, from federal reservoirs. So those three are all ready to go, they all use existing infrastructure, putting the drill bit in the ground and accessing the reservoirs, bringing the oil to market is only a function of getting regulatory and legislative agreement to allow us to go forward.

COMMISSIONER BYRON: Well, my question, where I was headed on all of this, was your initial concern that you brought up about the potential for any leaks. When you are using infrastructure that could be 40, 50, 60 years old, isn't that a concern?

MR. SPARANO: It is not a concern based on the amount of aggressive regular constant diligent inspection by MMS, and they are on those platforms every day, every week.

There has been a great deal of improvement in technology and leak detection, as well as subsea valves, shut-off valves that would have, in fact, stopped an event like the Santa Barbara spill had that technology existed 40 years ago, so that, Commissioner Byron, there is never any day we get up where there is no risk, every day we get up, though, we are doing everything we can to ensure that what is in place is more than adequate, and that all the new technologies that are available to us are being used.

COMMISSIONER BYRON: Good. Thank you. I see Mr. Schremp has stepped forward. Perhaps he wants to add something.

MR. SCHREMP: Thank you, Commissioner Byron. Gordon Schremp, senior staff with the Energy Commission. To shed a little light on those numbers that you are talking about in the crude oil, those numbers are actually a combination of federal data, as well as data by the applicant for Tranquillon Ridge. The federal offshore agricultural shelf numbers are from the DOE and SPR's analysis of how fast and what quantity of crude oil could come from Pacific waters and, arguably, the lion's share of those reserves are off of California. So we have used those numbers and we have used their timeframe of, you know, likely a decade to get appreciable volumes, and that is because of the very lengthy process, the five-year plan development, as well as in subsequent bid process, and an EIR and EIS process to even get the first offshore rates going. The second source, as recently discussed, is from existing facility Irene, offshore, Plains All-American has published some numbers that they have forecast how much oil and in what period of time that will become available, and we have used their numbers as part of our report development. So they are a combination of federal data and applicant data for Tranquillon Ridge.

COMMISSIONER BYRON: Thank you. Mr. Sparano, thank you. I was a little concerned in your presentation, you know, when you started with *The Scream*, by Mr. Munch, you know, that painting was stolen, at least one of them, in 2004. But fortunately it was recovered and so, therefore, we will not be blaming the oil industry for that, as well.

MR. SPARANO: Thank you, Commissioner Byron, very generous of you.

COMMISSIONER BYRON: But thank you very much for being here and for your presentation.

MR. SPARANO: Thank you, sir.

MS. KOROSEC: All right, next, we will hear from Gordon Schremp from the CEC staff.

COMMISSIONER BYRON: Mr. Schremp, you go right ahead because you have, I think, the record for what will be the longest presentation during the IEPR season, and we are a little bit ahead of schedule, but we are going to count on you to finish in time for lunch.

MR. SCHREMP: Good because, now, you do have seatbelts, right? I suggest you strap yourself in, I will go at a fast pace, a brisk pace, but certainly any questions anyone has, I would be happy to take those as I go through because I will be covering a variety of topics within the umbrella of renewable fuels, so I hope to shed some light on some of the concerns that some of the previous speakers have already noted, but also clarify some of the demand projections that are in part certainly based on what Malachi presented earlier, and how that will change.

So once again, Gordon Schremp, senior staff, Energy Commission. No doubt, the amount of renewable fuels, especially Ethanol, will dramatically increase in California. California currently uses about a little -- almost 7 percent Ethanol in all its gasoline. We have a little bit lower concentration than other places that do use Ethanol, almost any other place in the United States that has Ethanol is at about a 10 percent level, so we will soon be there, we anticipate next year. I will talk a little bit about that later.

So we have been looking at how much more renewable fuel is going to be needed, when, what the infrastructure impacts may be, and I think a lot of this is going to come down to what we believe is a significant increase in the amount of E85. The amount of Ethanol production in the United States has increased rather dramatically, as this slide indicates. Production through 2008 has reached a level of 9.2, and this is not production capacity, it is actual output, so over 9 billion gallons -- quite remarkable. And in 2006, we became number 1 in the world in terms of Ethanol production as a country, eclipsing that of Brazil, and Brazil remains second place, and we will share some of those figures a little bit later.

Well, along with the increased production in the nation, we have seen a jump in California use of Ethanol and we went along for a long period of time at less than 100 million gallons, but then there was a large jump in 2003, and then, once again, in 2004. And that was because Methyltertiarybutylether, another oxygenate choice at the time, was ordered to be phased out of use in California by the Governor. So once that was accomplished, the other oxygenate that could be used was Ethanol, in fact, the only one that is permissible to be used in California at this time. Any other oxygenates must go through a full fate and transport assessment for any potential deleterious impacts on the environment, or citizens, for health. So at this point, Ethanol is really the only option that can be used. Now, recently California was granted the ability to not use any oxygen in gasoline or an oxygenate from such things as Ethanol, but that position is essentially moot because the renewable fuels standard part two will dramatically increase the requirements to use Ethanol. And so I will get into that momentarily.

This federal standard, what we call RFS2, is a revision that is currently out for comment. Those comments are likely, I think, due in September and hopefully by the end of this year we will see some decisions by USEPA on what the final regulations may look like. Actual obligated parties have a renewable -- what we call an RVO, or Renewable Volume Obligation. It is a formula that EIA uses -- excuse me, USEPA -- and there is a calculation of what that number is. And then all the obligated parties figure out sort of what my volume is, and then they have a company pool members, company-wide, how they try to meet those obligations, and they have renewable identification of RINs, and these are basically a tracking mechanism, but probably more importantly, it is a way of tracking over-use. So if you use more than you have to by this federal mandate, you can actually bank those credits for your own company use the following year, a portion of those, or you can -- if you are going to under-blend, and not meet on your own, you can buy credits from those who have excess credits, and there are aggregators of RIN credits. So this will have some importance moving forward in terms of additional flexibility, but certainly when we talk about E85. Now, I want to stress, this is not a per gallon, that it is monitored on a per gallon basis, you basically have company-wide volumes to track your petroleum-based fuel quantities in the gasoline and diesel arena, and then what volume of renewable fuels during a period of time, and then what type of renewable fuels because, like the Low Carbon Fuel Standard, USEPA is also looking at different types of renewable fuels and their carbon tests, so those would be the advanced renewables such as Cellulosic Ethanol. These are the numbers through 2022, beyond that date in our analysis we assumed these numbers were flat, not changing, we did not increase them, but it is likely that these numbers will rise post-2022. But Congress, USEPA will decide this and there will be a comment period. I should also note that, on the far right, we have the biomass-based diesel, it goes up to one billion gallons in 2012, and then the same throughout this period. I further anticipate that this number will rise. That is, as you will see when we go through the biodiesel numbers, a very modest goal, as opposed to the other renewable fuels, which is a fairly aggressive goal. So that is likely to change as we move forward, but these are the numbers we use to figure out how much we would need in California. This just takes those numbers on the table and displays them on a chart over time. As you can see, in 2008, there was more Ethanol used in the United States, conventional Ethanol, than the obligation -- about 600 million gallons. And those are probably excess RIN crests that have been banked, and there are likely some RIN crests that were also carried over into 2008. We do not know what those numbers are. But the over-compliance is probably much greater than as portrayed there, or at least greater than. But we do not know how much more. So that will help in 2009 for compliance.

Now, how much Ethanol were we going to use here? Well, we set some ground rules in our analysis, we assumed a couple things, first of all, that fair share calculation, we are going to blend the Ethanol here, not purchase credits outside of the state borders, so, you know, physical blending and physical requirements for renewable fuels, primarily Ethanol, here. Secondly, we assumed that there was really no credit purchase to help you with regard to compliance. You have to do it by volumetric blending each and every year, and I think a third important point is how much Ethanol can you blend into gasoline. Well, we think California is going to have an upper limit of 10 percent, which we expect to be at next year. There is discussion of E15, 15 percent by volume Ethanol and gasoline, going above the 10 percent Ethanol "blend wall," as people refer to it.

EPA is considering comments on that request as a waiver and there should be a decision some time later this year, we hope. But even if EPA does approve E15 for higher Ethanol blend wall, do not believe that will be a viable option in California. California's gasoline regulations are based on data and testing and vehicles and fuels up to 10 percent by volume of Ethanol. There is no data and analysis on the emissions impacts beyond E10. So the Air Resources Board would actually have to go get new data, do new vehicle testing, or obtain vehicle test data that is applicable to California fuels and vehicles, and then rework those equations, re-workshop, develop a whole new regulation, that is a multi-year process, if that was pursued. So at this point, we assume California is going to be E10 max in low level blends, and any Ethanol beyond that in gasoline would have to be in the form of additional gallons of E85. And we will see why that is pretty important.

So we look at that as a worst case ethanol demand scenario for both the high and the low demand. And as you will see, I will show you and Malachi showed you the initial -- what I refer to as the initial gasoline demand forecast -- they will change. In the RFS2, the federal mandate drops those numbers further, drives those numbers down, significantly increases the E85, the retail infrastructure that is necessary to accommodate that kind of volume, and especially important, the number of vehicles you will need to actually use that kind of fuel.

So here are the numbers. They do rise rather dramatically, quickly, 1.5 billion gallons, 2000 and below, and upwards of almost 3 billion gallons of ethanol. And this will be of all types of Ethanol, of course, by that time. So these are very aggressive growths, but they are driven primarily by, or solely by the RFS2 obligations and how we calculate fair share. Just to point out that we did use two different EIA forecasts, Malachi touched on this. We compared our high price, which is a low demand forecast, with EIA's revised base case, which is a high price. So that is sort of the denominator used to figure out what percent of gasoline do we have each year in a forecast period, relative to the nation. And that is how you figure out what your fair share is. Same thing we do for the high demand case, which is a lower price. We use the low price EIA from their annual energy 2009. So you end up with these two sets of numbers and those are all in the report, all the numbers themselves, I am just showing them graphically here.

What I like to point out in this slide is basically that we expect, even though I state that next year we think we are going to beat E10 in just about all the gasoline, not necessarily so, there are some portions of the distribution infrastructure that are proprietary, refineries have their own pipelines, distribution terminals, they do not necessarily have to go to the E10, as Kinder Morgan, the common carrier pipeline is doing January of next year, but if they want their gasoline to remain fungible, or able to be continually traded, if they have an upset problem, or exchange agreements, then they too will have to be at E10. So not necessarily every gallon, but a majority of the gallons in 2010, we are anticipating in the analysis all of the gallons. I just point out that it does not necessarily have to be so. But by 2012-2013, RFS2 will basically require all the gallons of E10 to meet compliance with fair share in California. And beyond that, a whole bunch of E85.

So here are the load demand forecast numbers, and the upper dark line is the band or the trend that Malachi showed you earlier, and then overlay the RFS2 obligation, and it pushes that demand for gasoline -- in this case, E10, these are E10 gallons -- down by 9 percent by 2020, 9 percent further by 2020, and 12.3 percent by 2030, so that is a significant further dampening than the already low gasoline demand forecast. And, as Malachi stated, well, why is that happening? E85 gallons are going up and they are displacing, in part, on an energy basis, a certain portion of E10 gallons. And the increase is rather dramatic, going up to almost 2 billion gallons. So that is what it looks like. Those are the impacts on the gasoline and the E85 and, oh yeah, the bottom line here? The red number? That is the base case. There is a base case forecast for E85 in California, it is based on consumer preference surveys, the number of vehicles currently in existence in California, flex fuel vehicles, and the percent of time a consumer elects to purchase E85 when they go to a location that has both gasoline and E85 available. And that is a very small percent of the time when the price is the same on a gasoline gallon equivalent basis. And I will get into this in just a minute why that is important. So the base case modeling assumed very little E85 even though there are a rather significant number of vehicles in California.

High demand, the impact is similar. We see a further dampening of gasoline demand from the initial forecast, 7 percent, by 2020, 8.7. Not as bad. And then the E85 volumes are up a little bit higher, a little bit more than two billion gallons.

COMMISSIONER BYRON: Now, before you go on --

MR. SCHREMP: Sure.

COMMISSIONER BYRON: Mr. Sparano is still here and I am not going to put him on the spot, but I just wanted you to know that we certainly would be interested in hearing from you in written comment as to whether or not staff has this particular issue correct, Mr. Sparano, and if you want to comment now, that would be fine. But I am just interested in hearing these pressures on Ethanol, on E85, and the E10, if indeed these demands look realistic for these commodities. Written comment would be fine.

MR. SPARANO: Thank you for the astute observations and I will be really brief, but we will provide something more complete. But one of the big issues here that I think Gordon and the staff know very well is you have an RFS2 requirement that is way way beyond, even if your fair share calculation is a little bit off, way way beyond what we can currently put in gasoline with the 10 percent blend wall, and the requirement to have E85 be not only available in the marketplace, but available in abundance with a full infrastructure in refueling is what makes it a big challenge. And until and how that happens, it is going to be difficult to get beyond the 10 percent, only 10 percent, and the falling gasoline demand requirements as depicted here in the staff report will make it even more challenging. So this is one that is going to bear a lot of good policy work and collaboration in order to meet both needs.

COMMISSIONER BYRON: Thank you. I look forward to your written comments on that. Mr. Schremp, go ahead.

MR. SCHREMP: Thank you. A good segway, there are a few issues you might say, with regard to E85 retail infrastructure. And to be fair, there has not been a strong development of E85 infrastructure in California, there has been in other states that have probably been -- have a stronger support among some consumers in terms of E85 purchasing from their FFV vehicles. But in California, a lot of FFV vehicles, but not a lot of opportunity. That is changing. Over the last year, there was at least 26 stations available to the public now that have E85 dispensers, and that number is growing. Propel is one of the companies that has been very aggressive in this area to try to have more E85 available to tap into that market of FFV vehicles. But as you will see soon, from our outlook, you will need a heck of a lot more than what has been done so far, but to be fair, there has not been this mandate, if you will, that is going to result in what we believe are -- you actually have to sell a whole bunch of E85.

VICE CHAIR BOYD: Might not the Low Carbon Fuel Standard provide such vehicle, pardon the pun.

MR. SCHREMP: The Low Carbon Fuel Standard will actually exacerbate the challenges. I am only speaking specifically of the dramatic E85 increase and the infrastructure needs from RFS2. But, Commissioner Boyd, you are right, the Low Carbon Fuel Standard will possibly be requiring an even higher concentration of E85 than staff has indicated in the report, and that is part of the uncertainties, and I will get into that in just a few minutes.

VICE CHAIR BOYD: Okay. And my other thought was, Mr. Sparano pointed out that the industry has not the foggiest idea how to meet the Low Carbon Fuel Standard, but you get credit for alternative fuels, this is an alternative fuel they may choose to put on an island or many islands throughout California -- only a thought.

MR. SCHREMP: Okay. Well, just I think stepping back 30,000 foot level, you look at the RFS2 regulations, they are really for the people that are bringing in the fuel and producing the gasoline. Those are sort of the obligated parties, if you will, primarily. Really, the retail station owner and operator, which in the United States, standing California, the majority of the stations are owned by a sole owner, meaning one person only owns one station, and that is it. That is over 52 percent of the stations in the United States. So these are not company owned and operated, big oil company retail outlets, this is really independent --

VICE CHAIR BOYD: How many of those are branded though?

MR. SCHREMP: Yes, and those are supply agreements, that is correct. But most of the obligations for what you have at your station, and what infrastructure you may elect to alter, those are decisions by individual owners in many cases. So that will be part of the challenge that I will point out. So staff looks at that as an apparent disconnect, if you will. A large obligation by providers of fuel, yet where is the infrastructure requirement? There really is none, and it also extends to where is the vehicle availability requirement. So two areas of concern and certainty at this point that certainly have time to be worked out as we move forward.

So speaking of retail infrastructure, staff looked at some different assumptions about the amount of fuel going through a typical dispenser, if you will, and the greater the amount of volume per year, such as 450,000 gallons per year, you end up with a smaller need, this is the two lower numbers down here of additional E85 dispensers, upwards of nearly 5,000. Now, I will also point out that this chart that I am using here this morning is slightly different than the one in the report. The one in the report used an incorrect reference in a dataset, so these are the correct numbers and we will certainly have this revised chart in the corrected staff document once we finalize that. But they are in the same ballpark, just a little bit lower. And then, if you assume that, for example, we are at about 150,000 gallons, then it is these two sets of middle numbers, you are well over 10,000 additional E85 dispensers necessary to meet just the RFS2 E85 obligations for E85. And then, if you go up to a level of that of what Minnesota is currently selling per -- these are actual figures, 74,000 gallons per year for all their E85 dispensers. They have a good dataset and you will have to obviously have far more dispensers if that is the case, if that is the throughput per E85 dispenser at that future time. Now, a good reference point, if you will, is how many dispensers are there in California at all the stations? Forty-two thousand. That is for all fuels -- premium, mid-grade, regular grade gasoline, diesel fuel -- at retail, and a small amount of alternative fuels. So these are very significant numbers of additional E85 penetration that we believe would be necessary to achieve compliance with just the RFS2, let alone how the Low Carbon Fuel Standard may add to this requirement. That kind of restructure, like anything else, has a cost. We have seen cost estimates ranging in between $50,000 to $200,000, that is a very large estimate. I think the National Renewable Energy Lab and some of the papers, White Papers they have done, looked at a number of, I think about $60,000-$70,000 as a benchmark. Put that number in context, if you are one of those single sole station, single owners, those kinds of people were averaging less than $33,000 pre-tax profits, so what kind of money do they have available maybe to get financing or even pay for cash for some of this? That will be a challenge. And we have to look at that all those stations, or most --

not all -- most of the stations that have installed E85 in California have done so with some partial financial assistance, or even complete assistance from other funding sources, so it is not basically their money, so that is obviously going to have to change, unless there is a policy in the state that says, okay, well, we are going to spend upwards of -- and I know the figures -- it is a couple of billion dollars to get this done. So that is certainly something to consider, but we are not suggesting -- staff has not suggested that in this document.

And another issue that was raised in the April workshop was the fact that Underwriters Laboratory does not have an approved E85 dispenser. This issue is being worked through. It is our understanding that those new E85 dispensers have been installed after receiving waivers, essentially, from local agencies. But if one is going to have widespread distribution of E85, we do not know if that current model will suffice, moving forward. We will have to see.

Now, does this make good sense from a business perspective to spend that kind of money? As I mentioned before, you are looking at an equipment investment of $60,000, how much margin do I have to have per gallon of E85 to break even? This is just to break even. So this assumes we are making a 10 percent return on investment. You have to be probably in the neighborhood of less than $.20 per gallon for every gallon of E85. And the most sensitive aspect to this is how much volume per dispenser on an annual basis. So if you increase the volume up to 140,000 gallons a year, you can reduce that margin to about $.12 a gallon. But if it is less than the assumed $70,000, then you have to have higher and higher margins just to break even, not make a profit, just to break even with a return investment of 10 percent. Now, as another point of reference, all this year in California, so far, I think through the first week of August, we have seen an average margin at retail of $.12, which his down here. So once again, just on a pure business sense perspective, this appears as though it will be a bit of a challenge, as well, assuming a $60,000 investment. Make this a $100,000 investment, then the numbers on these minimum margins go up even greater. So something to keep in mind.

Another aspect of widespread E85 sales at retail is that the -- a gallon of E85 will not take you as far in your car if you operate a flex fuel vehicle, as compared to a gallon of E10. And those estimates range between 22 and 20 percent less distance, or a reduction in fuel economy. So staff has considered, well, what would be optimal for consumers? Maximize the amount of information to a consumer in California so they can make a more informed decision.

Well, gasoline gallon or fuel economy equivalent pricing requirements at California retail would be a good start. So we have concluded that, if the Division of Measurement Standards were to look into this and pursue that kind of requirement, I guess in order of consumer fairness and more informed decision-making, we think that would be beneficial. And the reason is, a national study of E85 retail pricing shows that consumers were actually over-paying by an average of $.29 a gallon, compared to what the lower green line is on the gas and gallon equivalent pricing. Now, they may be electing to do this of their own volition because they think, "Oh, it is more green, I want to do that," but the fact of the matter is, in almost every other location in the United States, there is not gas and gallon equivalent pricing. It is just, "Here is the price per gallon of E85, here is the price per gallon of gasoline." And so the consumer would have to know how much Ethanol is in the existing gasoline, would have to then do a calculation based on the fuel economy differential with a calculator, and then say, "Ah, yeah, that price is cheaper. I will go ahead and buy it." But they do not see that. They see a price difference of $.25, $.40, $.50, and go, "Oh, great deal," not necessarily so. It depends on what the base gasoline price is. And to put that in perspective, if gasoline is only $2.00 a gallon, the E85 would have to be priced $.44 to

$.56 per gallon less than that number. Now, it has been raised as a potential source of additional funding, or a way of offsetting this discount that a retailer would have to post to attract enough E85 supply -- purchases -- is these renewable identification number of credits, they do have value. And once again, I mentioned the retail station owner and operator has no RFS2 obligation, but who gets the REN credits for the E85? That is a good question. That is a question open to debate. We understand those branded stations with those supply agreements, some of those supply agreements are being re-written to clarify who gets that because this is money, it is over $.10 a gallon, it is as high as $.16, and as we move forward these values could rise, or they could drop, there is no certainty there. But this is a tangible value that could be used if the retail station owner is accruing these, it could help offset that lower price that they will have to offer for E85. So we will continue following this and this will start to become more evident as we get closer to 2010-2011.

The final component of E85 that is very important is an adequate number of vehicles to actually use the E85, sort of the chicken and the egg extension from retail now to the vehicle side. We have a significant number, 382,000 as of October of 2008, but that number is going to have to grow significantly, 2.4 million by 2020, and over 3 million by

2025. Now, the number of vehicles that staff is calculating depends on how frequently you are electing to put in E85. Do it all the time? That minimizes the projection of additional FFV vehicles. Do it half the time, twice as many. So this next slide sort of points that out. This is the track of FFV vehicles in the population in the database. This lower number on this left-hand side scale is the percent of time they elect to put in E85 when there is a filling event. As you can see, it never exceeds 10 percent. So that is a very low rate, and that is based on consumer preference surveys, responses on E85 price at the same price as gasoline, on an energy equivalent basis. So that tells us, at least in this California sampling surveying that consumers will want a further discount in E85 price before they put that in their E85 vehicle. So that is important. So you see this divergence is based on the increase in E85 gallons and how many additional FFV vehicles will be required, assuming 100 percent E85 filling, which we believe is unrealistic.

These other numbers are 75 percent -- the higher numbers, and so we do not even show 50 percent, which would probably take you above 4 million vehicles, FFV vehicles, by 2022. So a significant number of E85 dispensers anticipated would be required to meet RFS2 obligations for E85 and a significant increase in the number of FFV's available. Now, we do mention in the report, but I do not have on a slide here, that there are other policies, if you will, to reduce gasoline demand, and that may include additional hybrids, plug-in, hybrid electric vehicles, full electric vehicles, fuel cell vehicles, these kinds of vehicles are not necessarily FFV's, obviously, and so the automobile manufacturers have an increasing challenge under Pavley to offer more and more fuel efficient vehicles.

So here is where we could see another possible sort of fighting out of two policies, one where a whole bunch more E85 requires a whole bunch more FFV's versus, "Well, I do not want to sell my FFV because I want to get Pavley compliance, I want to sell something else." So it is something that bears further investigation to see how this might work out, but once again, another challenge and uncertainty that we discovered in our analysis.

Now, after covering the federal standard, we will switch gears to the California standard, we have already mentioned this a couple times, the Low Carbon Fuel Standard is a carbon reduction per gallon standard, so reducing the intensity of that gasoline gallon, and that is done primarily through uses of other blend stocks that are lower in carbon, and the commercially available ones right now are Ethanol and, as Mr. Sparano pointed out, not necessarily all Ethanol is lower in carbon intensity, and that is correct and I will show that next. But this kind of shifting of from the Low Carbon Fuel Standard will likely shift the flavors of Ethanol required to meet compliance, which is different than the volume metric, absolute volume metric fair share just for plain old Ethanol that we have calculated under our RFS2 analysis. So the purpose of this chart is to, "How long can I use a certain type of Ethanol in E10 blend?" Now, we admit that compliance can be accomplished through purchases of credits from mobile source vehicles, so that helps maybe to extend the amount of time you use a certain type of Ethanol in an E10 blend. I could also blend a higher concentration of E85 earlier, and then, in my total mixture, I still come out complying with the Low Carbon Fuel Standard. But at some point you are going to run out of credits and you are going to run out of E85 blending to allow you to continue use of E10. So this is certainly an issue because, as I point out in the RFS2 compliance, we show continued use of E10 all the way through the forecast period.

E85, on the other hand, has a number of different Ethanol types in California, or Brazilian, these are commercially available now, that can be used in E85 blend mode and achieve full compliance with the Low Carbon Fuel Standard. But once again, we do not anticipate the entire state going to E85. That seems unrealistic, extremely costly, and would raise questions about even supply adequacy of Ethanol, beyond the large numbers under the RFS2 calculation we have already come up with. So there is an awful lot of uncertainty still in the Low Carbon Fuel Standard, less uncertainty in the gasoline because there are a number of pathways that have been identified, and their carbon intensity is both direct and indirect. Most recently two new pathways, included here, for Brazilian sugarcane, one you are actually producing electricity at your Ethanol plant in Brazil, and excess electricity, and in another you are actually mechanical harvesting of the sugarcane, rather than burning the field ahead of time. So those are important changes and they have improved the carbon intensity, lowered them, if you will, and it has helped on the E10 side, but is not that important on the E85 side, unless you are looking at the mixture of the two.

So there is still a lot of uncertainty here. We know that there are other means of compliance. We are looking at it per gallon for the fuel compliance. We know it is not as simplistic as that, it is more involved, more complex, and does have additional flexibility, but that has an awful lot of uncertainty, the amount of credits that may or may not be available from a original engine manufacturer for these other types of vehicles, and, as I will talk about in the biodiesel side, there are still pathways that have not yet been identified, or quantified, into their carbon intensities that will allow us even to calculate how much additional biodiesel could be required, and I will talk about that in just a little bit. Any questions before I switch over to the supply side?

As you saw from the production increasing of Ethanol, yes, of course we are using it more in the United States, over 700,000 barrels per day, and, yes, you like the change of the units from gallons to barrels, but be that as it may, and as you can see from this busy chart, the red are imports and you do not really see a lot of imports most of the time, in fact averaging only 1.2 percent in 2009, so a small component of total supply, but at times, back here, in 2006, a very important component. Now, where do those imports come from? Primarily Brazil, the second largest Ethanol producer in the world, and an important source, we think, moving forward, and we will talk about that, as we transition to greater Ethanol use in California, and greater E85 use, under the umbrella of the Low Carbon Fuel Standard.

No surprise that, when you look at the average concentration in gasoline in the United States, including California, is over 7 percent and that is through May of 2009, that average concentration will obviously keep rising as the RFS2 obligations kick in through 2022, and depending on what the gasoline demand does, it may rise at a faster pace if the gasoline demand is either flat, or actually declining, because that is the base of your denominator.

Now, more Ethanol production, greater Ethanol use, increased concentration in gasoline, wow, the Ethanol industry must love that. Well, yes and no. A measure of profitability of gross profit per bushel of corn processed, assuming 2.8 gallons of Ethanol per bushel of corn, you see that, by this index, if you will, a rather steep drop in a measure of profitability, and a bit of a rise, a recovery in most recent numbers through the end of July. Good news. So this is primarily due to an over-supply of Ethanol beyond either targeted Ethanol concentrations in non-mandated markets, gasohol blending, E85, such as that. There is plenty of supply right now. And on top of that, there was a large run-up in the feedstock price of corn last year, and still rather pricey now, and that has hurt the profitability of facilities. So we expect this is temporary, as RFS2 mandates continue to grow, that this kind of profitability measure will rise over time possibly back to a level, certainly sustained over a dollar, maybe possibly two. But certainly time will tell and it is dependent upon additional capacity that is being constructed, although many of those projects canceled or delayed because of the poor economy and the downward trend in gasoline demand.

So no surprise here, with poor economics you have had people shut their plants voluntarily, temporarily, cease operations, and that is what this blue color is in January '09, and in June '09, a large amount of idle capacity. The red bars are the amount of what is under construction at that time, at that snapshot. And obviously, as you see here, a large amount under construction. "Well, gosh, by the time I get here, my production should be up there." Well, how come it is not? Well, some of the construction projects typically are delayed, and in some cases cancelled, never come to be built. But, as you see, the capacity continues to climb and we suspect this will go upwards of 15 billion gallons before all is said and done, and it is getting close, right now, a little over 13 billion gallons of actual in-place capacity with some more under construction. And what is the magic 15 billion gallons? Well, that is the RFS2 conventional Methanol from corn limit, 15 billion gallons in the standard. So you can blend more, but you are not helping achieve compliance with anything by doing that.

Now, that is conventional Ethanol. Cellulosic, I think this was touched on by Mr. Sparano. Cellulosic Ethanol currently 4 million gallons per year of capacity, operational. Another 5 million could be by the end of this year. So that is almost 10 million gallons. The obligation starting January is 100 million gallons for 2010. It is unlikely there will be that much of cellulosic Ethanol available to meet the obligation. We have concluded -- staff has concluded that, instead of setting this standard, and clearly there are some challenges of meeting that goal by the producers, that you may want to consider something that Oregon has elected to utilize and that is build it first and then the regulation kicks in, and that is what they have done with their biodiesel standard that has just kicked in. Once the biodiesel facilities are at a certain level, for three consecutive months, then the regulation for blending downstream kicks in on the obligation. So it is something the EPA may want to consider, but we probably suspect they are getting an ample amount of comments on cellulosic Ethanol portion of the regulation in the comment period. And so we will find out what EPA does do, and also acknowledge that EPA does have the ability to alter, suspend, delay a component of RFS2, but think of yourself as an obligated party trying to comply ahead of time, setting up your contracts, your supply agreements, you need a little bit more certainty than, at the last minute, somebody comes in and says, "Ah, there is not enough, I'll just cancel that." So that is certainly an issue and will become more of an issue if there continues to be a problem making cellulosic Ethanol viable on commercial basis, and cost competitive, because the obligation is to ramp up rather quickly over the next five years.

So I guess on the U.S. side, we have to say, for the next couple years, should be ample supply to meet the RFS2 obligations. So now we will take a look at Brazil and Brazil's importance, especially for the Low Carbon Fuel Standard in California. Just to compare and contrast real quickly, the average output from a plant in the United States is about 50 million gallons a year, and a little less than 20 in Brazil -- smaller plants in Brazil, more of them. And another important thing is, the Brazilian facilities will actually -- they are looking at another market. This is not just, "Where can I sell my Ethanol, my primary output, and I have some co-products like in the United States?" If they have distiller dried grains, for example, it is a co-product they also sell and has value. Well, in Brazil, every year there is this, well, how much -- what is the price of sugar? How much can I sell my sugar from? Don't convert the molasses to alcohol, just make it into sugar and sell it to the world sugar market. And Brazil is a huge provider of sugar on the world market. So, as those sugar prices go up and down, or supply and demand fluctuates, some of that Ethanol or that sugar cane more wants to go into the world market, so there is that interactive dynamic, if you will, that constantly goes on the Brazilian market. In addition to that, the amount of

Ethanol in gasoline, at about 24 percent, I think, by volume, at low level blends, is -- that can fluctuate and it can be set at different levels. So there is -- and the demand in gasoline in Brazil can change, and the demand for E85 or almost E100 for their FFV's can fluctuate. So there is this dynamic that goes back and forth that, having said that, it does not guarantee that build an Ethanol plant in Brazil and it is going to produce Ethanol. Now, their production has been going up and you will see here, there are two different types we refer to as hydrous and anhydrous ethanol, in two different growing regions in Brazil, and hydrous basically contains a certain amount of water and anhydrous has nearly the absence of water. The hydrous goes into the FFV markets that is gas containing ethanol anywhere from 24 to 100 percent by concentration, anhydrous goes into the low level gassing blends. Some hydrous ethanol is also exported to some Caribbean basin countries and those facilities will take that Ethanol containing some water, they will dehydrate that, get that water out of there, make it anhydrous Ethanol, and then export that to the United States, so that is another means of hydrous Ethanol getting to the marketplace on a global scale. Speaking of global scale, you see the exports of Brazilian Ethanol have been growing over time, reaching a record level in 2008, almost 1.4 billion gallons. We expect that to go up in the future because we think there will be a strong demand certainly in California, and also in the United States for advanced RFS2 compliance. And just to point out that there is an import duty and to add more on tariff on Brazilian ethanol, and other foreign countries outside the Caribbean basin initiative, and that does, I guess, make it costlier in some analysis that we have looked at, some economic modeling analysis that we have looked at, suggests that the price of Ethanol in the United States could be lowered by anywhere from 2.5 to 14 percent, a modest amount, if you will, yes, but still a reduction that could then be passed along to the consumers, at least a portion of that. So this does, in effect, increase the price of providing Ethanol to the marketplace in the United States, but we also understand, on the other side of that coin is this is a bit of protectionism that is probably designed to help the domestic ethanol industry, and so there would be some pain and suffering on the Ethanol industry side, and domestically speaking if this is removed, as well, most likely.

So some Brazilian estimates. UNICA, the sugarcane trade group, and ETBE, which is basically their energy and mines association, they have forecasts of growing exports, these are billions of gallons, and California use would want most of this over -- or a large part in here -- over the next five to 10 years, so we do hope that this does come to pass, but there are competing forces for Brazilian exports, it does not necessarily go here, and it is not necessarily the highest price. For example, Memorandums of Understanding with Japan, as Japan tries to achieve carbon reductions, they have elected to increase the amount of Ethanol being used in their gasoline, albeit in the form of an ether, ETBE, rather than just pure Ethanol blending at this point, but their demand is going to go up and they are looking, and they have some supply agreements in place in Brazil to obtain the necessary Ethanol for use in their country. So more Ethanol exports from Brazil, yes, but not guaranteed they will come to California, not even to the United States, let alone California, so this is another competing force for a type of low carbon intensity Ethanol we think is going to be necessary to meet Low Carbon Fuel Standards in California.

Now, there has been a mention of logistics and certainly the complicating factor, one aspect of the Low Carbon Fuel Standard, is the flavor of Ethanol, that has a lot of uncertainty associated with it, but the issue is it does not come by the same logistical chain of events to get to the retail station. Where that comes from, how it gets into the state initially, are different means of conveyance. And so this is important in terms of compliance with the Low Carbon Fuel Standard in how companies are actually going to do this, is what kind of instruction will then be necessary because, as you can see here, the dominant amount of Ethanol is coming in via rail cars. Now, there is an infrastructure in place, especially in Southern California with the unit train unloading facility, it is very efficient, the systems worked very well, the industry has responded remarkably well to ensure an adequate supply without interruption. So this system is working very well. We do have a growing in-state production up through 2008, and then that economic profitability news for Ethanol producers, I showed you earlier, well, that translates through to California facilities, and basically all but one facility in California is shut down, I believe, at least at the time we were doing the report, and is idle. So we expect those facilities to come back as economics improve, and so we will see more in-state production, but mostly we are an importer of Ethanol, and rail Ethanol for the Midwest. We do get a little bit of water-borne Ethanol foreign imports, Caribbean Basin Initiative Ethanol, and Brazilian Ethanol, but a small amount because it has not been necessary, there is plenty of domestic Ethanol available. So our rail infrastructure in place, distribution terminals set up to do this, but that has been at a level of about 6-7 percent. Kinder Morgan is going to go to E10 and they handle the majority of the gasoline in California, and they will be accepting base gasoline that only gets blended with 10 percent Ethanol. So we expect most of the system, the rest of the state, will follow suit. We think it is likely there is inadequate infrastructure in place, there is some question about how quickly the rail facility in Southern California can ramp up, this has to do with some uncertainty of some of the participants in the marketplace willing to sign-up to do that, because of when they think E10 is necessary versus when the market is going to transition. So that is still being worked through, so we are following that closely. And there are also modifications that have already been accomplished through the distribution terminals, more storage tanks for Ethanol and a greater ability to receive more trucks, because that is how the Ethanol gets in the distribution terminal is via truck, almost solely in California, but that is not how it initially gets to the state, that is by rail. So as I mentioned, 86 percent by rail. Kinder Morgan is working on a project in Northern California, in the Richmond area, to be able to bring in unit trains in Northern California, that would be a first, and it is a different process in that the tanker trucks are loading directly from the rail cars, it is called a trans-loading process, and I believe Kinder Morgan is going to talk about that today. So if that project is completed, we think there will be sufficient rail import capability in

Northern California to handle this increase to 10 percent Ethanol and we do not anticipate any problems there. Marine facilities, on the other hand, we are not quite sure if there is adequate capacity to bring in water-borne Ethanol, a significant amount. We understand that various marine terminals can use tanks that are in another service, like gasoline, or gassing blend stock components right now, but when you use an existing tank that is already in service for another service, then you are decreasing the import capability for that other type of commodity. But in time, this can be worked out. There are two ways to bring Brazilian Ethanol into California. One way is directly to an existing marine terminal that is adequately set up, there are a couple that can already do this. And then another is to bring into a marine terminal in another part outside of California, load into rail cars, and bring those rail cars into California and use the existing rail receipt and offloading facilities. So those are two means we see viable for increased amounts of Brazilian Ethanol. Primafuel, who is here today and going to be speaking about their project in Sacramento, does have something like this to accommodate up to 400 million gallons a year of Ethanol receipts, and this can be over the water, and they can -- please correct me if those figures are wrong. But construction has not started. They do have permits in hand, but they have not started construction. They need enough people to basically sign up and to make that the going concern, and we will get an update on that. Brazilian Ethanol going through the Houston Ship Channel, rail cars in California, well, Kinder Morgan will also talk about that. They have a project that they are looking at developing to be able to handle that kind of Ethanol receipt and transfer.

If there are not any questions on the logistics, I will keep moving forward and now give you the whole food for fuel that seems to be in the popular press. "More Ethanol? Well, you are going to make my cornflakes go up in price." All right, well, let's take a look at some of the historical information in agricultural statistics and then, more importantly, some of the projections. No doubt, the amount of corn being used for its Ethanol has risen dramatically, almost 3.3 billion bushels in 2008 and, as you can see, in 2003, we are a little over 1, so that is more than tripling in a period of six years. And as a percent of total corn use, it is now upwards of 33 percent and, then, once again, you go back to 2002 and it was a little bit less than 10 percent, so that is a rather dramatic increase in the percent of corn that is now actually being converted into fuel Ethanol, but no surprise in the strong increase in production. Corn has other uses. The dominant one is feed and residual uses, these purple bars, but as you can see over time, the red bars have been growing in size and, in 2009, are projected now at 4.1 billion bushels versus the 3.3 in 2008. So are they going to have to plant a whole bunch more corn, acres of corn? Not necessarily. Why? The yield of corn has continued to increase at a remarkable pace, and primarily in the 1980s you saw -- or up through the '80s -- you saw post World War II significant application of fertilizer that increased yields, and then you have seen introduction of better and better strains, more resistant to disease, pests, as well as higher yields per bushel, and then using geo-space information systems where you can actually apply fertilizer, for example, in a un-uniform manner, you apply it where it is needed based on satellite imagery in your field, and not the same concentration over all of your acres. Same with watering, tilling, everything. So these advances have allowed for a remarkable continued increase in yield that is forecast to go even higher. So what does that mean? Well, the amount of acres harvested and the amount of corn certainly can get a little bit higher. Case in point, I am assuming a million acres of corn harvested in 2008, 32 million less acres than the record in 1917, but four times the yield. So about a third less acres and four times the amount of corn, that is because of yield improvements, and those yield improvements are expected to continue. Looking at the forecasts from

USDA for plantings, and I have elected to use three types of crops that people consider as trading off one another when I talk about the Food for Fuel, corn, soybeans, and wheat, and we see total plantings are forecasted to go down, actually, not even increased, go down 1.7 percent compared to 2008. Well, their yields are going up which is why their production, in total, actually increased with plantings down. So it looks like there will be higher yields of corn, higher yields of wheat and soybeans, so that is how additional production will be obtained without as much effort as one might think. And this is a look at the forecast for the amount of bushels required to produce Ethanol and it is over 5 billion gallons by 2018 -- 5 billion bushels by 2018 to produce the Ethanol. And on a percent basis, we are seeing a leveling out of about 41 percent from the 33 percent in 2008. So a little bit higher concentration of corn being used for this purpose, but other corn uses are going up -- feed and residual use, primarily.

So it looks like, I guess summarizing, that the agricultural marketplace appears to be able to handle this increase in conventional corn-based Ethanol that is required in the RFS2, so we do not see a lot of issues there. Now, we also want to point out that this is not as controllable a process as, say, a refinery operation is. A lot of the corn grown in the Midwest is dry cropping, it is dependent on rainfall that is occurring in the summertime. Change the rainfall patterns, change the amounts you get, lower yields. Have some flooding, have some freeze events, and you alter the yields. So those projections are certainly not a guarantee, but with fairly high corn prices, the farmers certainly endeavor to try to produce as much as possible to meet these growing anticipated demands, but some of the necessary ingredients to have a successful harvest are literally beyond their control.

Now, biodiesel, the production has been growing rather dramatically, not quite 700 million gallons in 2008, this is actual production, not production capacity, which is much higher. So, you say, "Well, we're going to use a whole bunch of that," well, not so fast. A lot of that left the market. Where did it go? It went to Europe, primarily. Well, Europe has a higher marketing price for the diesel fuel and so that is where it found a home. And the European community, the EEU Council said, "Well, let me get this right. You're getting a dollar a gallon to blend in the United States, and then you come over here and compete against our farmers. We don't think that's fair." And so there are basically sort of two sets of tariffs that were put in place for the next five years that are essentially designed to offset that benefit that some of the blenders in the United States were getting from the dollar a gallon credit. So we anticipate that the export quantities will drop dramatically in 2009, and that biodiesel will find a home in the United States, and then rise above these numbers, which never even get above 1 percent in average biodiesel use in diesel fuel in the United States. So we think this will go up. So, a policy to give a dollar a gallon blending credit, and yet really no change in the average concentration used in diesel fuel.

The RFS2 does have a biomass-based diesel component and, once again, fair share calculations, our diesel forecast in California versus a comparable EIA forecast for diesel fuel, came up with these numbers. And it never gets to 65 million gallons, so these are rather modest goals, staff believes, for biodiesel use, especially when you consider in 2008 we estimate there was already 50 million gallons of biodiesel already being used. So meeting RFS2 fair share in California does not appear to be any problem whatsoever in terms of supply. And that is because there is a tremendous amount of excess capacity in the United States. There is 2.3 billion gallons of production capacity and another 600 million on its way if all of that gets built. So, plenty. Since you may recall, the RFS2 requires 1 billion. So there is already plenty of capacity to meet the RFS2 all the way through 2022, but as we mentioned earlier, we think EPA will raise that 1 billion gallon target to higher and higher levels, we just do not know how much, but certainly you could do that, and there is adequate supply to do that.

Well, looking at Europe, Europe is the largest producer of biodiesel. They have 2.5 billion gallons of idle capacity due to poor economics of biodiesel producers at this time, like that in the United States. So plenty of spare capacity, if you will, in Europe to tap into it, if necessary, but not even necessary under these modest RFS2 goals. This is just graphically displaying that information on a spare capacity, idle capacity, the dark red versus the yellow. And I believe that the actual production capacity in 2009 will approach 9 billion gallons, so much higher than even this chart indicates. So lots of biodiesel capacity coming online in the United States and in Europe.

As is the case with gasoline, there are even a greater number of uncertainties for biodiesel under the Low Carbon Fuel Standard, and that is because we do not have enough pathways for where is the carbon intensity for both direct and indirect for different types of biodiesel. What we have now is basically yellow grease, animal fat pathways, but one cannot make a viable argument that that is going to be an adequate supply in the United States. There is a finite limit to that material to convert into a biodiesel. Certainly, crop sources are going to be more of what is going to be used. So, not having the pathway, staff has been unable to analyze what kind of impact biodiesel demand may occur because of Low Carbon Fuel Standard in California. Once those new pathways do come out, we would be doing some follow-up analysis; if it is does rather soon, we will have some of that in the finalized report, but it is likely something that will continue following next year in the off-year IEPR cycle. But just looking at B10 or B20 levels, 10 percent level and 20 percent level, we are looking at 400 to 800 million gallons, significantly more than the 50 million gallons in 2008. But certainly, adequate supply in the United States to handle that increase, if the Low Carbon Fuel Standard drives you to that level. It could even drive you beyond that, but like I said, we do not know at this point in time. There are some infrastructure issues, but there are some differences compared to E85. Basically, the difference on the retail side is you really do not have to do much of anything. Well, if I am getting diesel into my diesel underground storage tank, well, go ahead and put that B5 blend in there. No harm, no foul, I use my existing retail pumps, pipe, tank, no change. Go to B20, well, okay, maybe I have to change some seals and maybe change my hose, but pretty much very minimal investment. Now, there is an issue on the wholesale side. Why? Where are you making your B5? Well, where do they blend the gasoline with

Ethanol? At the distribution terminals. Same thing is going to have to happen with biodiesel. So if you have widespread use of B5, for example, you need basically all the distribution terminals have to have a biodiesel, a B100 tank you would tap into to make your B5 blend. So the wholesale infrastructure is going to need some modifications, but this can be done in a relatively short period of time -- 12 to 24 months, not a problem, not a concern, depending on the pace, and depending on whether or not you have a mandate that every single gallon must be B5 versus a average statewide goal. Far different impacts on the infrastructure requirements because, then, you could let people who already have the capability to dispense out biodiesel more efficiently up to the point you need the whole market to do that. So there are ways around that. There is an underground storage tank, or UST, issue. The tanks currently in use that have diesel fuel, conventional diesel fuel, are allowed to have B5, but tanks of a concentration higher than 5 percent, up to 20 percent, they have to have sort of independent testing verification that, yeah, that is okay materials-wise to put in B20. That has not been done. The California State Water Resources Control Board has recognized that they do not want to essentially stand in the way of increased use of biodiesel, so there is essentially a three-year variance so you can go ahead and put that B20 in that existing diesel tank underground, and that three years should allow sufficient time to those approvals, if you will, to be worked out, worked in the system, and I think they are taking comments on their proposal through September, and they are welcomed to comment, and we have been working with them before in the past on this issue. So assuming no increase beyond B20, modifications at the retail, again, should be negligible. That does conclude my remarks. Oh, look, exactly noon.

COMMISSIONER BYRON: You did very well. And a lot of information, a lot of very good information. A couple quick questions. I am going back to page -- your slide 56 where it shows a lot of fluctuation on yields, primarily for corn, so I would expect that that is that seasonal issue you were talking about -- not seasonal -- that is that annual variance that we might see. What might that do with prices? Have we modeled that? Have we looked at that? If we exceed or drop well below demand, what would that do to prices for Ethanol -- food-based Ethanol?

MR. SCHREMP: Not being an economist, but --

COMMISSIONER BYRON: I am going to ask you other economic questions, too, and you are right, it really does stretch what we ask you to do, I agree.

MR. SCHREMP: But economists, even economists on our staff will tell us, that there is a relationship between a decrease in supply availability when demand remains the same, that the prices should go up. And so, yes, we have seen that in the past in these agricultural markets. But I have to say, what happened in 2008 was not supply-demand based as many claimed, with the run-up in the commodity markets. I am talking about corn, soybeans, wheat, and I am talking about oil, and I am talking about copper, all those commodity markets zoomed to the moon. Supply-demand? I do not think so. Then, because they dropped off the map after reaching record high levels, demand did not change. So what was going on there? Well, an awful lot of money was flowing to those markets -- increasing demand for those futures shares. And so that caused sort of an aberration, if you will, both on the crude oil side, as well as in the agricultural markets, and some of that translated through to increased costs for those companies. But that was not a supply-demand reaction in those commodity markets. But we have seen, absent last year what went on, we have seen that corn values can drop, that the farmers are going to receive when it starts to become more known, like, "Oh, we're going to have a bumper year," over-supply, price drops. "Oh, no, didn't get the rains," yield very small, the plants that are behind schedule in their development, okay, prices go up. Yes, that does happen. So, primarily what is going to happen is that those will directly affect the economics of the Ethanol facilities. Now, if the effects are great enough, there will be some more idled facilities on a temporary basis, moving forward. So that is one potential impact of a price increase because of an unforeseen, underdevelopment of a crop in a particular year, for other factors -- lack of rain, bad winter, etc. So, yeah, we expect that those fluctuations were primarily some weather-based and also some -- what you do not see on here since this is the actual bushels harvested, you do not see the amount of acres planted because what happens in these crops is another behavior, if you will, that the farmers will collectively say, "Okay, what were the prices this year? Wow, the prices tanked. I am out of corn and I am into soybeans." And so you see people do actually move -- shift their fields to make an annual crop, they are going to change it every year if they want. So you will see people chase a price -- prices were good? More plantings the next year is usually what you will see. Prices were down? Less plantings, absent anything else. So there is a reaction by the acres planted and there is a reaction in the market and the amount of bushels actually harvested compared to the demand that is anticipated.

COMMISSIONER BYRON: Good. You are becoming an agricultural specialist, as well, I can see.

MR. SCHREMP: Necessary in this increased renewable world we are in, yes.

COMMISSIONER BYRON: I think we will stop here. It is noon. Thank you very much, excellent presentation. We will reconvene at 1:15. Thank you all very much.

MR. SCHREMP: Thank you, Commissioner.

[Off the record at 12:03 p.m.]

[Back on the record at 1:00 p.m.]

COMMISSIONER BYRON: Welcome back, everyone. This is Jeff Byron, Chair of the Integrated Energy Policy Report Committee, and with me is Commissioner Boyd, and we are reconvening our Transportation Fuel Forecast and Analysis IEPR and Transportation and Fuels Joint Committee Workshop. It looks like we have got some stakeholder presentations this afternoon. Are you our lead, Mr. Schremp?

MR. SCHREMP: Yes, I am.

COMMISSIONER BYRON: Good. Go ahead.

MR. SCHREMP: Thank you, Commissioner. Welcome back. We are going to start with Joel Velasco. He is from UNICA. And, Joel, in a second I will let you sort of describe what you do for your organization and what UNICA does. I know that is in your presentation. But Joel is going to speak to us remotely and I will go ahead and control the slides. So I will pass the mic to you, Joel. Go ahead.

MR. VELASCO: Thank you very much. Everybody can hear me, I presume?

MR. SCHREMP: Yes, we can.

MR. VELASCO: Great. So my name is Joel Velasco, the Chief Representative for North America, of the Brazilian Sugarcane Industry Association. I apologize for not being there present today. I was in Brazil until Saturday and my family had not seen me in about two or three weeks. I thought I could use the videoconferencing to do this instead.

COMMISSIONER BYRON: That is perfectly okay, Mr. Velasco. This is Jeff Byron. We are glad to have you and we are seeing a lot more folks doing presentations by WebEx. That is a good thing.

MR. VELASCO: Okay. Well, maybe I will ask CARB to give me some carbon credits. I think I have been in California almost every month this year.

VICE CHAIR BOYD: I could buy some from you. This is Commissioner Boyd. I have got a little notoriety lately about not buying carbon credits for travel.

MR. VELASCO: Okay, well, again, let's go to the next slide which I believe has -- okay, I just want to make kind of two broad points, one is just to briefly describe the industry and what we are doing in Brazil, what we are producing, because I think it is a critical element of your analysis. I have read through the report, I think you guys have done an admirable job of doing this. I do not know how many times you have been to Brazil to do that report, but if you have not, it is pretty impressive. And then, the second part of this, I really want to talk about kind of meeting the RFS and the Low Carbon Fuel Standard impacts, both from a supply and demand perspective. And then I will be glad to take some questions. Next slide, please.

So first, let's talk a little bit about the Brazilian sugarcane industry. I think it has been pointed out before, we produce food, fuel, and now electricity, and I think we will be doing some other products going forward, in fact, some of them with California-based companies. Next slide, please.

UNICA is the leading sugarcane industry association in Brazil, representing a little bit over 100 producers, both cane growers and mills that are usually vertically integrated in Brazil. Our member companies are responsible for roughly about 60 percent of all the Ethanol and all the sugar that is produced in Brazil. A third product for our company is electricity, we call it bio-electricity for some differentiation, but it is basically co-generation of electricity from the bagasse, which is the dried stock and other materials from the cane process, and it is a byproduct. Today that bio-electricity meets about 3 percent of Brazil's electricity needs. We believe, easily within the next decade, we will be meeting about 10 percent of Brazil's electricity needs. This is a critical element, I think, of the balance sheet of any sugarcane milled in Brazil today. A lot of focus abroad is on Ethanol, but we like to point out that, when you grow cane and you process it, you get at least three products today. And my presence, whether virtually in this meeting, but around the United States often is part of an effort by UTICA both to educate various groups, but also to try to engage in a dialogue about dealing with some of the challenges and opportunities that we see ahead for our industry. Next slide, please.

So I think the report does a pretty good job of describing how Ethanol is produced in Brazil. But let me just try to graphically show you a way to think about our industry. On the left side of your slide there, you see a little bit of sugarcane. We grow about half a billion tons of cane, or at least we will grow more than that this year, and that will be processed into mills. At the mill, the cane is squeezed, and the juice is made into either Ethanol or sugar. I remember earlier in the presentation somebody mentioned Molasses. Unlike other mills in other places of the world, our Molasses is actually -- whatever is left is actually converted back into Ethanol. And then we are left with a dry biomass, a pretty abundant biomass, which is often referred to as bagasse, and that is burned at the mill, at every mill, to produce steam and electricity to power both the mill and it usually leaves quite a bit of surplus electricity to be sold into the grid. So this year, we are estimating for all of Brazil about 7 billion gallons of Ethanol will be produced, about 31 million metric tons of sugar will be produced, and about 15,000 Gigawatt hours will be produced of electricity to the grid. Again, all of these numbers have been increased over time. Just while I am here, let me just try to mention a few things, some that have already been said, but any mill in Brazil, in general, has the ability to adjust how much Ethanol and how much sugar, how much fuel or food, however you want to look at it, it can produce. Due to, in large part, due to the fact that India, which used to be the world's second largest exporter of sugar, I believe, until last year, became a net importer of sugar for reasons unrelated to fuel, the world price of sugar has been increasing quite rapidly, in fact, I think it is one of the best performing commodities today in the world since the beginning of the year. That has led all the mills in Brazil to produce as much sugar this harvest as they can, and so what you are seeing is a return to a lot more sugar production because the price of Ethanol is low. This year, we are estimating that about 55 percent of an average mill's production will be for Ethanol, and 45 percent sugar. It is usually within that 60-40 split, but that is important to understand the dynamics in Brazil.

What is really driving demand for Ethanol, I spoke a little bit about sugar, is really the Brazilian domestic market for Ethanol. We have two types of Ethanol in Brazil, the hydrous and the anhydrous. The hydrous is what is used in our flex fuel carbs in Brazil, it has about 5 percent water, but because it is a tropical country, we have no problems with E100 blends in our flex fuel carbs, and then anhydrous, which is blended with gasoline. Hydrous Ethanol demand has grown quite rapidly, in fact, total Ethanol demand just this year alone has increased nearly 18 percent. Now, this is at the same time we are suffering from fiscal economic challenges, not just in the U.S., but around the world, we are seeing stronger and stronger demand for hydrous Ethanol. Why? Because Ethanol remains very competitive with gasoline in Brazil. The second reason for a strong demand for Ethanol in Brazil is flex fuel vehicles. For the first half of the year, 92 percent of all the light vehicles sold in Brazil were flex fuel, capable of taking Ethanol in gasoline. In fact, comparing the first half of 2009 data with the first half of 2008 data, we see an increase of 5 percent already. Today, we have about a third of the auto fleet of Brazil already flex fuel, and we believe that we will reach 50 percent in the not too distant future. All that does is it provides more flexibility to the consumer because he can opt at the pump to make the choice of fuel based on price. We have in every fueling station in Brazil either gasoline, which is really E25, or E100, hydrous Ethanol, available. I will also note just in passing that we -- historically, Brazil is a little bit like Europe, has a lot of small vehicles. We have now seen in Brazil that Honda launched the first flex fuel motorcycle. For a developing country, motorcycles are a major means of transportation. I think we have as many motorcycles as we have cars, and while we have historically focused only on small vehicles for Ethanol in Brazil, we are now seeing a lot of success with SUVs, or at least larger vehicles, pick-up trucks running on E100 or flex fuel. It is very different than the U.S., where the SUVs were the first ones to go to the E85 in large part, I think, because of the CAFÉ credit. So we have been very successful in Brazil, I think, with Ethanol today and the fact that we use electricity, we now are able to say that 16 percent of Brazil's total energy demand comes from sugarcane, about 45 percent of Brazil's total energy demand is from renewable sources. So we feel we are quite well positioned. In fact, if you go around Brazil today, you discover that gasoline is actually the alternative fuel. Ethanol is the largest fuel used in Brazil, liquid fuel for light vehicle engines. Next slide, please.

Then, I think though gasoline is the alternative fuel in Brazil, we have been able to achieve -- to basically replace 50 percent of our gasoline consumption with about one percent of Brazil's arable land. In red there, you see the areas or the regions where sugarcane is grown in Brazil. I was just in South Central Brazil, outside of the state of San Paulo there, which is really the hardest sugarcane country, last week. And we expect that most of the expansion is going to occur in and around those areas. The next slide, please. Next slide. Thanks.

The final thing is, just before I will move on to some of the specific issues in the U.S., this is UNICA's estimates, and I think there was a reference to it in an earlier slide, these are the actual numbers that we have projected, both out to 2015 and 2020. These are not based on an incredible amount of scientific work from the standpoint of kind of, you know, hard to plot out what policy changes are going to occur in every country in the world, much less in any states in the world, and also these projections were made before the economic crisis, and we have not yet been able to revise them. But what you generally see there is that we see growth in all areas, both in sugar production, as well as in Ethanol production, and we see very strong growth in Ethanol for domestic consumption in Brazil. Why? Because we are not expecting -- we are not building into these projections the possibility that, on a price basis, even if policies when sent by the use of sugarcane Ethanol broad, then on a price basis will be necessarily advantageous to ship Ethanol to the U.S. I think what is critical for you guys to understand in this context is that, all this really shows is that it is eminently -- Brazil is eminently able to increase supply of Ethanol over the coming years, but a lot of this will depend on the prices and the trade policy associated with it. Just a caveat for those who are really looking closely at numbers; sugarcane harvest in Brazil is really an activity all year long, depending what region you are in, but in South Central Brazil, which is the main area of Brazil for sugarcane production, that production occurs usually starting in April and goes all the way to October and November. And so that is why, when you look at data, you will see two years up there, 2008, 2009, that is just the crop year. Next slide, please.

Let me move on to the second part of this presentation, which I think is more relevant to some of the findings of the report. I want to talk a little bit about meeting the Renewable Fuels Standard and the Low Carbon Fuels Standard, and the role of sugarcane and Ethanol in that market. Next slide, please. Here, I think, has been described quite well, so I am just going to make a couple points here, first, this is the famous, or infamous, depending which perspective you have, Renewable Fuel Standard. This is what the EPA has been asked to implement via the RFS2, as they call it. If all goes according to the law, or according to a plan, the U.S. would be having a very large volumetric mandate by 2022, there would be a limit to how much conventional Ethanol or biofuel could be used for that, such the yellow. The blue is the cellulosic biofuel -- notice I am not saying "Ethanol" here, but biofuel, the loss of biofuels, so it does not necessarily have to be Ethanol. And then the bright green, if you can see there, is the advanced non-cellulosic biofuel that most people, including myself, understand would be where sugarcane Ethanol, at least immediately, would meet the target of at least 40 percent greenhouse gas reduction. And then the red is the biomass, bio-based diesel bucket. Just one comment that I think was in the presentations earlier, and this has to do a lot with these very high projections for E85 that I have seen in your analysis, as well as in EIA's. If you presume that the blue is going to be mandated, and that only cellulosic Ethanol would be allowed to meet that requirement, then obviously, if there is no increase in the blend wall, there would have to be a significant increase in E85. Based on what is pretty clear from EPA's analysis, and the reading of the law, they have ample room to reduce those requirements not to be -- in case cellulosic Ethanol is not available. I just point that out because I think time is going to continually look at this issue. I realize it still leaves a lot of uncertainty to the fuel distributors, especially the retailers, but I am quite suspicious of the very high demand for E85 going forward. Then, if we can go to the next slide?

Then, if we look at the Low Carbon Fuel Standard, this is sort of a very simplified way of thinking about it, just from the gasoline perspective, but as I think was pointed out by several, according to CARB, gasoline has a carbon intensity in California of about 96 grams of CO_2 per megajoule. The target is to reduce that gasoline carbon intensity to 86 in 2020. And the current calculations, including what I think is an exact rate of penalty for indirect land use of 30 for corn, 46 for cane Ethanol in Brazil, puts the numbers there -- you see corn Ethanol would be actually almost 100 grams, which would be higher than gasoline, and sugarcane Ethanol, in what I think is the most likely pathway that would be coming to California, would be 12 + 46, so you are at about 58 there. All that tells you is that, as CARB has developed their calculations right now, it would be very unlikely that corn Ethanol would be used to meet the LCFS, although I do think those numbers will be revised downward over time, I am certainly hopeful for that, on both the direct and indirect impacts, and then sugarcane Ethanol would have an impact. So, if you go to the next slide, actually, this coincides very well with your chart there in the report, but this is my own kind of simulation of, well, what if you could blend 10 percent sugarcane Ethanol in all of California's gasoline, what would that do to meet the LCFS? Well, you basically would get to about 2016 without counting the credits for the preceding year if you blended E10 sugarcane Ethanol, 10 percent sugarcane Ethanol, and 90 percent California gasoline. Then, theoretically you could probably use some credits that you have generated in the prior years out to 2017, or you could use -- you would then go to an E85 scenario. Now, this is a scenario that is just simply so you can kind of get -- I can get my mind around it -- this is not a scenario of how I think it will happen, in large part because we have, I think, a lot of infrastructure challenges and logistics, to say the least, about price going forward. So I really see this as a reasonable, but not likely scenario, if I could say it that way. Next slide, please.

So we now are in a situation where you can say, well, Brazilian sugarcane Ethanol would meet not only the federal standard, but the California requirement, and then it is a question of why the volume is there, and can you get them at a reasonable price. Well, first, I think -- let me say in terms of volume, I think that, as I showed earlier, there certainly are the volumes California, you know, faculty and low calculations for me have always been about a billion and a half gallons of Ethanol that would be needed to meet the E10 or so requirement, and then you have got theoretically another four billion gallons or so of the advanced pool in the RFS that I showed about three slides earlier. But those are not mutually exclusive because you can meet the RFS in California, and even if you generate extra RINS in California, you could use those for elsewhere in the state, so theoretically you could even have a scenario where Brazil would need to send somewhere around 3 or 4 billion gallons by 2020, or so, and would meet the requirements. So we are not talking about, you know, as some have, I think, incorrectly said, completely depending on Brazilian Ethanol. Now, on the price side, so you know, 4 billion gallons, yes, it is a lot, it is more than half of what Brazil produces today, but it is certainly something that we expect over the next five, 10 years, to be a reasonable increase in Brazilian production.

The second part really has to do with price, and that is really what this slide is about. It was noted earlier, but Brazil, any fuel Ethanol coming into the U.S.

has to pay 2.5 percent at the lower end tariff, plus a $.54 per gallon tariff. If you look historically, that has really meant about -- for those non-math majors like me -- that works out to about a 28-30 percent surcharge on imported Ethanol. And then, to be fair, I think many of you will know, there is a $.45 per gallon blenders tax credit that the fuel blender gets for mixing Ethanol with gasoline in the U.S. today. And then, if the import of Ethanol comes through a Caribbean country, it is exempt from paying -- it is dehydrated in the Caribbean country, or produced in the Caribbean country, it is exempt from the $.54 per gallon surcharge. But the effect of the trade policy is actually, for its complexity, it is pretty simple. It is to raise the price of Ethanol in the U.S. market, and not to let that inflated price provide any benefit to the exporter or the importer of the Ethanol into the U.S. So that is why, as you have seen earlier, Brazil, despite the fact that we are very efficient, we have a very low price of Ethanol, much lower than in the U.S., we have not been allowed -- we have not had any significant market share in the U.S. Why? Because ultimately we have to be -- we have about a 30 percent barrier in front of us. So, as I look at scenarios going forward for California, if California's demand for Ethanol increases, there may be well some shuffling of Ethanol from Brazil that normally enters through the East

Coast, and now we go through the West Coast, but unless prices adjust upward, there is probably not going to be a great increase, unless the tariff barriers get reduced. So this flag, what you see here, is just a simple scenario that we ran at the end of last year, and with the financial crisis we have not tried to re-run these scenarios. But we said, what if at the end of 2008, or in 2008, Congress and the U.S. decided to reduce the tariff to the level of the blender's tax credit -- that is the blue line -- or reduce the tariff altogether, and the tax credit -- that is the green line -- how much Ethanol would the U.S. actually receive from Brazil? Our scenario showed that, if nothing changes, Brazil will be shipping by 2015 a billion and a half, maybe 1.8 billion gallons a year; if there is parity, which actually I think Senator Feinstein has proposed legislation to that effect, you would have that volume increased about 4 billion gallons by 2015, and if there were no tariff at all, in fact, if we treated Ethanol trade like we treat gasoline, Brazil would be shipping upwards of 6-6.5 billion gallons of Ethanol per year to the U.S. Now, if you superimposed that on the RFS, which is those bars in grey, and just superimposed that on top of the conventional Ethanol and the advanced Ethanol mandate, I am not including in there the cellulosic, which you will see is pretty clearly -- in the total free market scenario, Brazil would still only have about a one-third market share in the U.S. under the RFS, which is, by the way, most people would think that this is an overly ambitious scenario, but I think it just points to this myth that, if there were no tariff, that all of a sudden that the U.S. would become dependent on Brazilian Ethanol. I think that is far from it. And more importantly, if we do not do this -- and I think this is where I would like to end -- consumers in California are likely going to have to pay a higher price in order for the Low Carbon Fuel Standard to be implemented because, if the only fuel that meets the standard is, at least for gasoline purposes right now, would be sugarcane Ethanol, and if Congress imposes a 30 percent tariff on it, I do not see how -- we are not going to produce Ethanol at a loss in Brazil, sell it at a loss to the U.S. simply because we think the policy is laudable. We do think the policy is laudable, but it runs head-on to the trade policy of the United States which, you know, penalizes a low carbon fuel. So I will end it at that. Hopefully you will have some questions, and I think my e-mail was there on the presentation, on the next slide, if you have any questions for me.

VICE CHAIR BOYD: Thank you. This is Commissioner Boyd. While I have got you, I would like to check some of the facts as I understand them and get accurate answers from a knowledgeable person like your self. You said, in Brazil, you offer E25 and E100 to the motorists. Is it truly E100? Because I have been operating under maybe incorrect information that says it is really more like E98. Do you denature with two percent gasoline?

MR. VELASCO: No, well, no we do not denature Ethanol in Brazil. We leave that here to the United States, but in Brazil, what I call E100 is hydrous Ethanol.

VICE CHAIR BOYD: Yeah, I heard that.

MR. VELASCO: And hydrous Ethanol has about 5 percent water content. So it would be correct in saying it is really E95 --

VICE CHAIR BOYD: All I need is ice-cubes?

MR. VELASCO: Yeah, well, when you make Ethanol from cane, you still have a lot of water in it and removing that 5 percent of water from the Ethanol for cars that -- for Brazilian flex fuel cars, it is a lot of wasted energy and money, and the car does run on 5 percent water. But you cannot blend hydrous Ethanol with gasoline.

VICE CHAIR BOYD: Right. Okay. It is my understanding that the sugarcane cycle is roughly a six-year cycle because initial production and the secondary production. Is that correct?

MR. VELASCO: No.

VICE CHAIR BOYD: Oh, good. My facts are all wrong.

MR. VELASCO: No, you are correct on one point. You replant sugarcane. Sugarcane is a semi-perennial crop. Think of bamboo meets grasses. It looks like bamboo a bit and every time you cut cane, you cut above-ground to process it into sugar and Ethanol, and usually that is a fifth, sixth, seven, eight years you have to actually replant the crop, that is probably where you got the six, seven year.

VICE CHAIR BOYD: Okay.

MR. VELASCO: Usually, from the moment I plant my cane, I can be producing Ethanol and sugar within a year because it takes about a year for the cane to grow. You only do one harvest per year, but as I think has been pointed out before, we harvest for about six months of the year in Central Brazil, and the other six months of the year the Northeast of Brazil grows cane. We do not store -- you cannot store cane after it has been cut for more than 24 hours because it begins to ferment. Actually, for California, think of grapes, you know, it needs to be treated a little bit like grapes.

VICE CHAIR BOYD: Okay. Now let me change the subject slightly here. You are quite aware, I am sure, of the very substantial concerns in the arena of sustainability and particularly in California the concepts of sustainability, which are defined by various people in different ways, but nonetheless, you may have heard discussion this morning of the full fuel cycle analysis, or cradle to grave type analyses. It is aimed at greenhouse gases, but it is really applicable to let's just say impacts on the environment, particularly when you are talking about sustainability. So, in California, there is a huge worry about air quality emissions. And I am wondering two things, I am wondering if you would comment on the concerns that some people have about, in Brazil, you burn the fields versus using mechanical harvesting, or there is some percentage of that; and secondly, it is kind of -- what kind of air quality emissions control do you have on emissions of even criteria pollutant from sugar processing plants, or the plants that ultimately produce the Ethanol?

MR. VELASCO: Sure. I appreciate the question. I have been in UNICA for about two years now, and from the very beginning we have put sustainability at the top of the agenda. In fact, we are, I think, the only trade association in Brazil now who has, at least publicly so far, called on Brazil to do a lot more as a government, both in terms of combating deforestation and things of that nature, so we believe in a holistic view of sustainability that is, you know, economic, it is social, it is environmental. Now, and so much so that, though we have serious questions about the lifecycle analysis that has been done up to date, including the indirect effect, we have been very clear that we are not questioning the fact that there are indirect effects, but the question of is the magnitude accurate. In terms of your specific questions on the environment, well, first, before the environment, let me talk about just the social aspect of this because it is a critical one for Brazil. We just actually published, and I will be sure to send it to you, a copy, first a full report done under the auspices of the World Bank of the sustainability practices of each Ethanol mill in Brazil, and what we found is we are quite ahead of where we thought we were, both in terms of labor concerns and of that sort, really, you know, providing education to our workers, worker re-training, and that sort. But really, on the air quality issues that you raise, first, one of the reasons that I insisted so much that CARB update their lifecycle analysis pathways for sugarcane Ethanol, was that they presumed that all sugarcane in Brazil is burned in the field. Today, at the aggregate of Brazil, about only one-third of the cane is actually harvested mechanically, one just needs to look at John Deere earnings reports to see how much money they are making from selling harvesters to us, to see that we are changing that practice. And a number of other governmental actions in Brazil and commitments that, by the industry, are basically meaning that sugarcane burning in the field is going to end. It will end in San Paulo, we have a date in 2014, because -- and, in fact, many of us expect it will end much quicker. I would venture to say, because of the separate pathways that CARB did, nearly all of the Ethanol that is going to be coming to the U.S., certain to California, is going to be coming from mills that have no burning cane, and co-generation of electricity, not because of any other reason other than the fact that, because of -- let's call it carbon credits -- given to those processes will encourage the evolution of the technology a lot faster. With regards to environmental standards and emissions standards for the mills themselves, it has actually gotten much more stringent. I was just last week in Brazil and was talking to one mill, for instance, who told me that, because he was beating the government's emissions targets, which have increased just recently, the government was now talking about raising them again. We have, you know, let's be clear, we are not -- I do not think that Brazil is going to have the exact standard that California does for emission plants, but it does not mean that it cannot meet those. Many of these mills, because they are receiving financing from abroad, whether it is through large banks here in the U.S., or even multi-national institutions, are being required to exceed Brazilian standards for emissions. And I will be glad to submit to you more written comments on that. We have submitted -- in the context of going through the E15 waiver process at EPA, we outlined in our letter there all the requirements of emissions standards for vehicles in Brazil, including those used in Ethanol. And what you generally find is that there is not a significant increase in emissions, generally, in fact, most of the emissions are actually lower with Ethanol; of course, from a CO_2 perspective, a greenhouse gas perspective, those are -- the plants are absorbing the tailpipe emissions, but there is admittedly a slight increase of VOCs, I think, that have been detected, and we are not ignoring that in our analysis.

VICE CHAIR BOYD: Thank you. And, yes, if you would submit some more in writing, we would appreciate it.

COMMISSIONER BYRON: Mr. Velasco, this is Jeff Byron. I have one quick question and it goes back to slide 7. I note that the electricity that you are producing from your byproduct, your biogasse, or whatever it was called -- bagasse -- is projecting to increase significantly, certainly at a much faster rate than your production of Ethanol is increasing. So does this mean a number of the Ethanol plants are going back and adding this capability?

MR. VELASCO: Correct. Thanks for the question. For brevity, I did not sort of show more details on that, but basically what you have in Brazil, and since we are on the slide there, the figures there are the average Megawatts, this is just a way to kind of compare apples and apples so that, when you are comparing it to a natural gas-fired power plant, roughly in Brazil today, the mills are exporting to the grid about 1,800 average Megawatts, okay? It is going to increase significantly for basically two reason, one, you are seeing a number of mills retrofitting, already a lot of them on their way, retrofitting from low pressure boilers to high pressure boilers. Until about 2002, 2003 in Brazil, sugarcane mills could produce their own steam and power from bagasse, but they were basically prohibited from selling surplus electricity to the grid. Those who know much about Brazil know that Brazil is about 80-90 percent hydro-based electricity, and the government controls that, so they did not really care to have much sugarcane-based electricity competing with hydro or even natural gas. So that is one aspect of it. There is going to be a big increase just from retrofitting of mills with higher pressure boilers. The second aspect of it is that, as we mechanize the sugarcane harvest, like in the state of San Paulo, by 2014, all cane will be mechanized, it is already half of the way there. Sugarcane, when you burn it in the field, you are burning almost a third of the biomass, or the plant, in the field prior to harvesting. That one-third is basically energy you are wasting. As you mechanize the harvest, you will be able to utilize about 40-50 percent of the straw, or also considered "trash" from that you were previously burning the field and bringing it into the mill. So, in essence, you are putting more fuel into your boilers. So in a simplified answer, we will increase it because we will increase the pressure of the boilers to high-pressure boilers, and then increase it because we will, in essence, be putting more fuel, fuel that was previously burned and wasted before. So we think those numbers are reasonable. Of course, if the Brazilian government decided for some reason, which I do not think they will, that they will not allow co-generational power, then we may have a problem. When mills sell electricity to the grid, CARB knows this well, we displaced a marginal power supplier in Brazil, which is natural gas and heavy fuel oil, so that -- from an emissions standpoint, co-generation in Brazil from Bagasse makes a lot of sense.

COMMISSIONER BYRON: Okay. Mr. Velasco, thank you so very much for your presentation. I think we could even spend more time on this, but in the interest of time, we have some other presentations to get to, so I think I will say thank you. And, Mr. Schremp, can we move on?

MR. SCHREMP: Yes, we can, Commissioner. Thank you, Joel. Thanks so much, and we look forward to both your World Bank Report you are going to forward to us, as well as any other written comments you may have, that would be great.

MR. VELASCO: Will do. Thank you.

VICE CHAIR BOYD: Joel, this is Commissioner Boyd. One quick question that just dawned on me. You mentioned the Caribbean being exempt, but isn't there a volume cap on the amount coming from the Caribbean?

MR. VELASCO: Correct. The cap is 7 percent of U.S. consumption of Ethanol from the previous year, so this year it is 7 percent of U.S. consumption last year, so it is basically this year about 600 million gallons will be the cap of Brazilian Ethanol, hydrous Ethanol that could be dehydrated to anhydrous Ethanol in the Caribbean, and entered duty-free. However, if a Caribbean country produces their own Ethanol from their own sugarcane, there is no cap. And this has been one of the things we have been encouraging them -- I cannot say with a lot of success -- to produce their own Ethanol. Ironically, they would rather -- they make more money selling Rum and sugar into the U.S. quota program than making Ethanol for U.S. consumption.

VICE CHAIR BOYD: Okay, thank you very much.

COMMISSIONER BYRON: Mr. Tobin, welcome. Please go ahead and introduce yourself.

MR. TOBIN: Well, thank you very much. Commissioner Boyd, Commissioner Byron --

COMMISSIONER BYRON: And you need to speak right into that microphone.

MR. TOBIN: Yes, sir. Commissioner Boyd, Commissioner Byron, thank you very much for the opportunity to come and speak to you. Gordon and I really appreciate the invitation, the quality of the presentations here have just been outstanding, at least for me out here watching you, a tremendous amount of effort and time that has been put on and it is greatly appreciated.

COMMISSIONER BYRON: Mr. Tobin, I apologize for interrupting you again, but you are going to have to turn the mic towards you, or speak right into it.

MR. TOBIN: I certainly will. A little better?

VICE CHAIR BOYD: Oh, a lot better.

MR. TOBIN: I am going to talk a little bit today about Kinder Morgan in a very general sense and the way that we do things, our presence here in California. I am going to talk a little bit about what is underway in terms of our investments in infrastructure here in the state, and how we view the state going forward. Ah, shoot -- all that talk about Rum is getting to me here.

Okay, just in a very general sense, Kinder Morgan overall is not an old company by any means, we are about 12-years-old, started out of the ashes of Enron, one small pipeline and two terminals, about 12 years ago. Now, something like 25,000 miles of pipelines, 165 terminals across the U.S. and Canada, set up into four basic business segments -- natural gas pipelines, CO_2 -- natural gas pipelines, I will talk about in a second -- CO_2 which is used in tertiary recovery of oil, especially in West Texas, from naturally occurring dome, products pipelines which are generally associated with a commercial pipeline of sorts, and the terminals group, our side. On the terminals side, we handle roughly 600 million barrels of products with throughput annually, about 100 million tons of bulk products, everything from coal, to pet coke, to aggregates and salt. This is the Kinder Morgan network as it exists today. Just a couple of things worth noting on here. We are right in the process right now of finishing up -- and I say this not because it is having to do, necessarily, with California, but it shows how we view things -- we are investing in what is called the REX pipeline, which originates in Western Colorado, and you see that sort of dash brown line that moves all the way across the U.S., into Western Pennsylvania, it is a 1,700 mile pipeline there to do nothing but take natural gas out of the ground in Western Colorado, and move it into eastern markets. This is a $5 billion project undertaken with Conoco Phillips and Sempra, partners that set up in a full take or pay basis, so regardless of what the markets do over the next number of years, this should be taken care of. Trans-Mountain

Pipeline, what you see up in Canada, in Alberta there, was set up something around 2005 timeframe, we now move crude out of the oil sands region up in Alberta through the Port of Burnabee in Vancouver, out to far eastern markets, other places, roughly 270,000 barrels a day, we put in an expansion and we should get to 300,000 shortly. And you will also note, of course, that in California we have essentially two sets of assets, first, the remnants of the old Santa Fe Pipeline, which in the northern and southern half of California, distribute the vast preponderance of the commercial pipeline, products pipelines, moving throughout Southern and Northern California, and another line moving from Colton out to Las Vegas, which is called the CalNET line. I should mention on this map, as well, that we have a substantial investment in the State of Texas. One of Kinder Morgan's predecessor companies was called GATX. GATX was set up to reduce the amount of redundant infrastructure some of the big oil companies had in Houston, by allowing them a central point of distribution out to eastern markets. It connects to both the Colonial pipeline and the Explorer pipeline, as well, and again feeds its way up to various markets throughout the east.

And with all this investment in infrastructure on the petroleum side, obviously from our side, the Ethanol movement for us was a big deal. Across the U.S., over the last number of years, as you might imagine, we have spent a lot of time and a lot of thought on Ethanol. That 35 million barrels in 2009 is roughly 1.5 million gallons or so, and, you know, overall demand right now is 9.5 or 10. It is a pretty substantial amount of product. And we have done this by focusing in on a whole variety of service offerings, for example, we can take in some of the product Joel was talking about, Brazilian product, CBI product, via direct vessel in, in the New York Harbor, in Houston, and in Tampa. We also have a series of terminals that are set up strictly as storage terminals, Chicago and Argo are often used as trading hubs for Ethanol throughout the Midwest. Additionally, we have a series of terminals that are tied to a product pipeline terminal, many of them you see in sort of the Southeast, the Richmond, Washington, D.C. area, are all connected to plantation system which needed investment to allow places like Virginia, North Carolina, Georgia, Alabama, to meet their own requirements statewide. Also, in the Southeast, we do a lot of rail transfer of Ethanol simply by virtue of the fact that you cannot set up a full unit train distribution outlet on a market that really does not demand it, size-wise.

Taking all this in total, you have to understand that the amount of time and effort that went into the overall energy transport industry of the last 75 years has been substantial. This network, of sorts, parallel network, for Ethanol has been set up essentially over the last five or seven. That being said, with logistics going on in Ethanol, it has been a little bit challenging. We like unit trains, we think they are a good idea, but as I mentioned earlier, it is very difficult to develop them. The major class one railroads in the U.S. have made a point of going to the Ethanol producers and said, "Look, as you develop your own facilities, please consider the fact that we are not going to agree to take them unless they are a sufficient size." So most of these plants in the Midwest are now somewhere between 100 and 120 cars worth of capacity and they can send a train out every four days or so, and very easy to do when you are on a large patch of dirt out in the Midwest, but very difficult to do when you are trying to take that train in a major metropolitan area like the City of New York, or the L.A. Basin. So much trickier in terms of development and betting there. And, as a result, you see very few places in the U.S. that can actually take a full train of Ethanol. L.A. Basin certainly was the first. There have been a couple in the New York Harbor area that have come about quickly. Baltimore has one now. Dallas has two. And of course, we have some in Houston, as well, various iterations I will talk about in a little bit. We have looked in great detail at the movement of product, Ethanol product via pipelines. As a matter of fact, that REX pipeline that I told you about, the Rockies Express, one of the initial versions of that was actually taking product that was moving through that pipeline, putting it on an additional line to do nothing but handle Ethanol. But Ethanol in a pipe is a very tricky thing. We have run a series of tests to allow ourselves better to understand how Ethanol can be distributed via pipe, and there are only a few conditions where it does make sense. We have taken one right now in Central Florida, and it is the only commercial pipeline that we know of that is moving product of any distance, and it takes product out of Tampa and moves it into the Orlando market, roughly 90 miles or so. But we had no fewer than 31 tasks that were done to that pipeline, which is relatively new, more like a 10-11 year pipeline, which is new in pipeline terms, and spent a good deal of time and money to make sure that there is no possibility, or very very limited possibility for any leaks. So, to that extent, we feel reasonably comfortable to duplicate that across a large segment of the U.S., say, for example, to feed California with a pipeline would be a much more difficult and expensive venture, which is why you do not see a lot of discussion about Ethanol pipes.

I did mention that the single car network in the U.S. is fairly vibrant, it is. We are doing it in a number of places. The problem with single car movements of Ethanol is that they are a little bit messy. The U.S. Rail network, unlike some of the passenger networks you would see in Europe, does not run to a fixed timetable and, if you do run short of product, it can be very very difficult to make up, so we see a lot of time and a lot of money being invested in uni-train facilities where they cannot support them as being worth it, at the end of the day.

A lot of this has been gone over in earlier presentations, so I am not going to spend a lot of time on some of this. I would say that right now, you know, we are figuring sort of along the lines of what we had seen in the presentations, which is something like a million barrels a day with a demand here in terms of gasoline, which would take what was at a 5.7 percent blend, 60,000 barrels a day, up to 100,000 barrels a day, looking into 2010 and beyond, very much consistent with the numbers that Gordon had shown there. What this means in practical terms is there is a lot of extra Ethanol that will come in to both Northern and Southern California, that has to be dealt with, and it has to be dealt within such a way where there is no too much pressure to put on the existing infrastructure to handle it. Gordon mentioned that we did have a working facility here in Southern California, and that is absolutely true. We made a rail terminal from a company called U.S. Development in

2006. At the time, it had been up and going for three years, it sat up in such a way where it runs by 2:16 a car unloading tracks, and it takes its product and feeds it directly into a pipe up to Shell Oil Products, U.S., which is about three miles away. From there, it is distributed via truck all the way across the L.A. Basin, as far as Colton and San Diego, 70 and 100 miles, respectively, so quite a wide distribution network for this facility. The reason it works is we are able to take a fairly substantial amount of product, and I would say a 96-car train, and get it unloaded in less than 24 hours. That involves less pumping time than you might think, a whole lot of switching time, to have it work and make sense. But as it sits right now, sufficient capability exists to handle not only the 5-7 environment, or the 7 percent environment we are in right now, to get fully up to 10 percent. We are running about 22,000 barrels a day, which is about 925,000 gallons per day on average through this facility, essentially that means 10 trains a month, or one every three days. We can go to easily one every two days. We figure a nascent demand would be somewhere in the area of 16-17 trains a month, without too much of a problem. Our program, really, on this side is not ourselves, but what follows up the chain on the distribution network. For example, our partner, Shell Carson, is limited on the amount of trucks that it can release on a daily basis. Right now, they are under permitting and they are trying to get their 150 truck a day limit, which is something around 28,000 barrels, up to 250 trucks a day. I cannot emphasize enough how important it is from people like in our business to work with their local communities and their local governing boards to make sure that the needs of the communities are addressed when handling Ethanol. As you may know, there was a fairly significant Ethanol terminal that was put in in Alexandria this year, Alexandria, Virginia, with great amounts of resistance from the local populous. Unfortunately, the way the railroads are set up, they have federal jurisdiction, and they can set up pretty much without being encumbered by city or state regulations, given the federal mandate they have. But it has been a very difficult subject across the U.S. in the handling of Ethanol, and where you put these facilities, and the sensitivities that you have for the community.

In the new train facility, we are also looking at investing here, Gordon alluded to it earlier on, this is a facility in Richmond, California, just down the way a bit. Ideally, this would not have been our first choice. We had looked at setting up a fairly significant and robust facility in Martinez, California, right next to the Tesoro Refinery, a beautiful place, nice place to put a rail, certainly out of any sort of population areas that would have given us any difficulty, fully connected to a dock aligned for imports and exports, you name it, but it is very very difficult to make that level of investment with an uncertain regulatory climate, certainly -- it is tough in any environment, and it is certainly tough on that side, that was roughly a $45-$50 million project. From our side, we are really dependent upon those who would invest in these operations to make them go, we will not do it sort of on a speculative basis. So option 2, as Gordon also alluded to, a lot of the producers this past year fell into great amounts of trouble financially, and as a result some of the assets that they had in play fell out, this happened to be one of them, and we were able to take this as a fully permitted facility, and set it up in such a way where I think, you know, within the next three or four months, we should be up and going and taking trains. It is not particularly elegant in that it is not connected to a storage or a pipe outlet, really, to speak of. We are going to go rail to truck. But we view this as an interim solution to something that might be a little more robust as legislation becomes a bit more clear, and some of our customers feel more comfortable in making an investment in a long-term facility. There is an existing facility up in Selby today, and Rahul is going to talk about his facility.

Investments are underway in various areas, just not an easy thing to do.

I am not going to spend a lot of time on this, I think we talked about it quite a bit in the last couple hours or so. We see the same sort of pressures going on. I was with a group of Ethanol producers from the Midwest last week and they are fully convinced that, you know, they will not be shipping Ethanol under current legislation in California 2014-2015 timeframe; it is going to bring about some pressures themselves. Where we see this getting a little tricky on the legislative side is that there are others who felt, or who have greenhouse gas initiatives very similar to California, and we mentioned this Regional Greenhouse Gas Initiative, this is a group of states that have banded together and, in fact, have said, "We think that the California approach is a good one. We are going to follow the path that they have laid out, and we are going to enact it in a very similar fashion." The sort of broad outline of that is that Brazilian Ethanol, as it has been described, becomes a pretty pretty sought after commodity. And there are some questions about how it is that Ethanol is going to be distributed going forward, and whether or not Brazilian Ethanol is going to make its way into California, whether it is going to make its way into Northeastern markets, or whether it is going to make it into other markets, as well. We see that there will probably be a competition of sorts for Brazilian Ethanol, almost as much as to take Brazilian Ethanol and put a bit of a premium on it, and have it traded in a separate fashion. We will see.

There are a variety of issues around the logistics that we are looking at of handling Ethanol originating from Brazil, that are interesting. Right now, coming out of Santos, or coming out of San Paulo, you have a couple of options on taking a large vessel, you can take it through the Canal, you can take it through CBI, or you can take it all the way around the Horn, back up into the California market to hit California. All those are a little bit expensive and a little bit challenging. The size of the vessels are roughly 335,000 barrels, sort of six-unit trains, let's call it, and when they arrive, they have to be multi-ported if they are coming in at that size because there really is not the storage infrastructure available in Southern California to take that quantity in product at once. So, as a result, we are looking at other ways to deal with that, which I will talk about in a second.

The other thing that we are looking at, as well, as this moves along, there has been talk about E15 and E15 certainly not in California, but in Midwestern markets. The fact that they are looking at it indicates that they are essentially seeing the roadmap on what will happen to their participation in the California market, and deciding that maybe they could keep that volume at home, rather than sending it out to the Coast on either side. You know, interesting the way they sort of take care of their own. There are, I think, 1,771 E85 stations in the U.S., right now, 31 percent of those stations are in Minnesota, Iowa, or the Dakotas. Ninety percent of the flex fuel vehicles in the U.S. right now do not have an E85 pump in their Zip Code. So I think, by watching the way that they react to this, I think they view this as sort of a natural resource that they are going to deal with in their own way, which makes this a very interesting scenario for us.

We also share the view that Brazilian Ethanol right now is very dependent upon sugar economics and what makes sugar economics go. I heard Joel and we are encouraged by his prospects and what he thinks is going to go on because we think there are real markets right here in the U.S. Gordon sort of alluded to this earlier, we do have a project underway right now -- because of what I described as the difficulty of moving Ethanol to the West Coast, there are a couple of different ways you could go about it -- we have a facility right now in the Gulf called Deer Park Rail Terminal, that we actually picked up about the same time as we picked up Lomita Rail, as well, and it is about a 1,100 car spot facility, there is no problem with us actually taking this facility, redoing it slightly, and having the capability of taking product here into low product and to send it out. The way this happens is via a pipeline that is connected to our Deer Park Rail Terminal to the Pasadena Truck Rack. If you can see KM Pasadena out there on the left-hand side of the picture, it is a fairly robust gasoline distribution area right there. Our truck rack is just to the south of it and, you know, if you can get product into this system, you have a pretty good way of getting out. But the way the legislation is working right now, and the way that we are viewing it, and what some of our customers are telling us, you can envision a situation where we would actually take in a trainload of corn Ethanol, put it into the existing distribution system, load that same train back out with Brazilian Ethanol, out to the West Coast, and do sort of a three-legged stool on it. Where it gets very difficult for us, in talking to some of our stakeholders, is around the idea of segregation -- does the Ethanol have to retain its identity by the time -- because Ethanol, as far as we can tell from a chemical standpoint -- is Ethanol, whether it comes from an algae source, whether it comes from cellulosic, whether it comes from sugarcane, whether it comes from anything else, chemically it is very much the same. But obviously, having the footprints that it does, and the values that are associated with the various origin points, makes the idea of segregating product a little bit tricky. For us, that means capital, a capital investment of sorts to make sure that the product itself is housed in the same -- in a way that allows it to retain its identity. So we are looking eagerly to see how all that transpires. For right now, the customer that we are talking to here is keen on optionality, as they usually are, just making sure that whatever investment decisions they make, they will be able to move forward with them later on.

So to sum up a little bit, I guess from our side, my Management has a fundamental belief in the RFS. I think you have to have a fundamental belief in the RFS going forward. If there is one thing you can believe in, that would be it. And in having that belief, you know that certain things are going to happen. We think in California, it will probably sort itself out in ways that we really could not understand right now, but that might work. In our business, we cannot go out and speculate, there is within our shop very few investments that are made without a firm customer commitment behind them. No Field of Dreams out on our side, for sure. We are generally going after some of the majors because investing with Ethanol producers, especially in the last couple years, has been very very tricky, and not something -- not a place you really wanted to be. We like the idea of working with the rail carriers.

There is a tremendous amount of flexibility in that work and it can allow us to grow in a way that makes sense. We have got a lot of experience in handling a lot of these products, and I can tell you, as the volumes increase, the experience in handling the product is very very important. And, of course, from our side, a clear bid on regulation and a good understanding on where you are going to go just really makes our life a lot easier.

So, again, if there are any questions. Thanks very much.

VICE CHAIR BOYD: Thank you, that was very educational.

COMMISSIONER BYRON: Agreed. Mr. Tobin, thank you very much. And I think we will forego questions and try to get back on schedule.

VICE CHAIR BOYD: I did learn -- I had no idea you rose from the ashes of Enron, that was a factoid I did not know.

MR. TOBIN: Actually, yeah, Rich Kinder was Ken Lay's right-hand man, and left in '97 because he did not like the way the business was going.

VICE CHAIR BOYD: Good.

MR. IYER: Thank you so much for the opportunity to address the -- oops -- to address Windows XP.

COMMISSIONER BYRON: That is all right. Please go ahead and introduce yourself while you are --

MR. IYER: Sure. My name is Rahul Iyer. I am a Co-Founder and Chief Strategy Officer of Primafuel, a California based biofuels technology and infrastructure company.

COMMISSIONER BYRON: Good, welcome.

MR. IYER: Thank you. I mention that only because I will be making some comments towards the end of my presentation on technology and how it is, in fact, relevant to this infrastructure conversation that we are having today. So I intend to recap the comments that myself and my company shared at the last meeting a few months back, prior to the draft publication of this report, just to remind you of where we are coming from and our thoughts on this topic, and then I would like to do a bit of an overview or a review, if you like, of the draft document and points that are made in the document that we think are critical to be either emphasized or retained into the final version of the document. And I would add a third item to this agenda in that I would like to add a few words on energy security technology and infrastructure.

So to recap last time, Primafuel spoke about one of our developments, a low carbon fuels bulk liquid terminal project that we have been developing for some time now at the Port of Sacramento, just on the other side of the river here. We believe, now supported in large part by this fantastic report put out by the staff here, that California is in desperate need of a significant amount of bulk liquids infrastructure associated with renewable fuels. And most importantly, having a lot of multi-level flexibility, marine terminal access, rail, highway, etc. It is precisely those issues that drove us to develop this terminal project, which has now come to be the first marine-based bulk liquids terminal, fully permitted in the State of California, almost a quarter of a century, 24 years. There has been a lot of discussion about how difficult it is to develop things in California, it is true, it is difficult to develop things in California, but it is not impossible. And I believe that there are two distinct responses one can have to a challenging business environment, one is to give up, and the other is to get creative and try harder. We pursued the latter strategy, I think, with some degree of success.

Previously in the discussion, it was noted that the terminal is permitted for about a million barrels of storage and that translates into roughly 400 million gallons of throughput, if you like, biofuels, on an annual basis. One of the things I would like to point out that maybe is not mentioned on this slide is that we were very diligent in the way that we developed this project, particularly on the permitting and entitlement side. Chiefly, we were focused in on flexibility. Again, not just in terms of the physical modes of transport, but also in terms of operational flexibility. One of the things we know for sure with respect to AB 32, the Low Carbon Fuels Standard, and RFS2, is that it is extremely difficult to predict to the gallon what kind of fuels will be used in the state, to what degree, where it will come from, and so forth. What we know is that trade flows will change and that the markets will need to be considerably more dynamic. In fact, this is not an accident, this is very much by design. The Air Resources Board has designed the Low Carbon Fuel Standard to create a more dynamic and competitive market, whereby the folks that need to comply, the oil makers and so forth, will be able to make the most cost-effective decisions on the lowest carbon fuels that they are going to bring to the California marketplace. That means that infrastructure has to get considerably smarter and considerably more flexible. For that reason, we permitted this facility not to be an Ethanol terminal, or a biodiesel terminal, rather, we permitted each individual tank on vapor pressure and toxicity requirements, or limits, therefore giving an operator flexibility in what kinds of fuels they might store there, including biobutinol, should that come to pass, and other molecules like that.

I would also add that we have created the ability here within our permitting to distribute E85 directly from this bulk liquid terminal, which is different than most bulk liquid terminals that do no real blending at all, and so being able to distribute or provide the Sacramento region with E85 straight from bulk liquid terminal further reduces cost and increases, hopefully, the economic availability of E85 to this region.

Again, I think I mentioned some of this on the previous slide, but some of the projections that we shared at the last meeting indeed are supported by some of the conclusions in this draft document, we are quite pleased about that. The upshot is lots more new fuels need infrastructure, that is pretty obvious.

I ended the last presentation with a rather bold request, if you recall. We asked that the Energy Commission be forthright and assertive in its demands of the industry to really explain to not just the government, but to consumers how industry is going to respond and meet these very very aggressive targets set up by the Legislature vis a vis AB 32. And I am quite pleased to say that we are very satisfied with the tone in this draft report, a tone that we think provides the right level of seriousness about the challenge before the State of California with regards to fuel availability and infrastructure. So, again, to recap that thought, we believe strongly that the staff at CEC should be extremely proud of the draft report in its current state. It is very well supported. There is a lot of fantastic data in it, and I really hope circulation is broad and wide because it is a very actionable document, if one cares to study it. And, again, the tone of urgency that is communicated in this document, we think, is good. It is responsible. It is not *The Scream*, so to speak, as we heard earlier today, but it is appropriate and we think that it is urgent. In fact, this kind of development, not only of infrastructure, but of new technologies, must continue at a fairly aggressive pace if we are going to meet these regulations.

Now, I will hit a few different topics, I will not read the quotations out of your own report because it is obvious that you have gone through it in great detail, but I will highlight sort of the upshot and some of the take-home messages. The work that was done in the report to highlight the impacts of the renewable fuels standard, the federal renewable fuels standard, Phase 2, on California's marketplace is really quite critical, the upshot being, of course, that RFS2 really does drive a significant volumetric change of the use of Ethanol in the State of California, not just Ethanol, of course, but other advanced biofuels including biodiesel. And I think the evidence is well supported and I do not need to beat that topic any harder.

On the Low Carbon Fuel Standard, there is a lot of work that was done in this particular report on various scenario modeling based not only on federal numbers, but on Air Resources Board's own numbers vis a vis the performance of various low carbon fuels. The upshot here, I think, is very important to understand, that the Low Carbon Fuel Standard does not accidentally change the trade flows and the types of fuels that we use in the State of California, it is intended to do exactly that. It is intended to create new more competitive marketplaces for our transportation fuels. And so should that create a new dynamic, a new incentive to use Brazilian fuels in California, well, then that is exactly what will occur. It is not by accident, it is quite by design. Should the United States adopt newer technologies to produce even lower costs and lower carbon fuels, then surely those fuels will find their way into California, as well. It is precisely this dynamic market, which is going to call for more dynamic and smarter fuels infrastructure in the state.

There has been a lot of discussion about the Low Carbon Fuel Standards, slightly less discussion around Reformulated Gasoline Standard in California, because that certainly impacts the state's fuel use dramatically, as well. We view the Reformulated Gasoline Standard very much as putting boundaries on what can and cannot be used as compliance tools in the state for carbon reduction. And I think there has been a lot of work done here and ultimately we think the upshot is that you have got E10 in the State of California for the foreseeable future, we do not think we are going to get to an E12 or an E15 very soon in California, we know that it took a few years to just get the air shed models done for E10, and some I would argue that are not quite done yet, getting to E15 in the next couple of years would be extremely challenging and unlikely. As a result, we think E10 is probably a low blend ceiling in California for the mid-term, at least, but E85 becomes the major compliance tool with regards to the Low Carbon Fuels Standard in California, with affective gasoline in the short and medium term. Looking ahead, lots of exciting developments on the radar, we will see where the technologies go. But, in short, that is the impact of the Reformulated Gasoline Standard.

Now, the draft report does address, obviously, the importation of blending infrastructure in California. I think, again, the upshot is that we need a lot more flexibility in the state. While there has been investment made in unit train infrastructure, as we heard from Kinder Morgan a moment ago, in California, much of that has been done in a piece meal fashion, not part of a larger, more comprehensive effort to upgrade California's capabilities. That does not mean that it does not work today, it does work today, but it works almost, if you like, beside itself. California does not have a very coherent biofuels infrastructure, it is a pastiche of small train unloading facilities at blending terminals, a couple of pseudo unit train facilities, and one fully functional unit train facility in L.A. The reality is that California needs a lot more flexibility, it has very little in the way of multi-modal infrastructure to bring in these biofuels, whether they are produced in the state, or in the Midwest, or offshore. So that is where I will leave that commentary.

A point on crude oil, which is not particularly relevant prima facie to the topic of biofuels, but in fact it is with regards to marine terminal storage. A lot of folks in the business are under the impression, at least theoretically, that crude oil tanks can certainly be swapped out and they can store some biodiesel on one season, and store some Ethanol in another season. While technically that may be true, the reality is that California already has a significant shortage of crude oil storage on the marine side. And so the likelihood of swapping out crude oil storage for storing another competing commodity is pretty unlikely, purely on economic terms. It is unlikely that that would occur. And as a result, we think new multi-modal infrastructure is required, or at least expanded capacity. One point here that the report makes early on in the draft is an allusion to a project at the Port of L.A., the Berth 408 project to expand crude oil storage. Now, that project has been going on, I think a little more than four years now, maybe more like six or seven years. Millions and millions of dollars have been spent just attempting to get permits in place. They are still not in place. So the question you have to ask yourself is, if we need the equivalent of one new bulk liquid terminal in the state of California every two years to meet these Legislative requirements, then at least one or two of these need to get permitted every year, and that has not been happening for about a quarter of a century, so we have got quite a backlog of projects that need to get built. I am not asking for permitting requirements to get softened, rather, I am asking for industry to get on the horse and start moving a little bit quicker.

So a few suggestions before I get on to my conclusions. As I mentioned, I think the findings in this report, or at least some of the data, are mission critical, not just the Legislators to understand to make smarter policies, but also for industry to really really absorb. The challenge, unfortunately, is that most folks that are out there in industry do not have either the time, or the inclination to read what is essentially an academic report at this stage. And so, if I could make some suggestions, I think that there are multiple subsectors of the fuels marketplace that are impacted by this kind of a report, I think it would be really really interesting if Executive Summaries of the report could be generated for each of these subsectors. I do not mean just a half page abstract, I mean a two- or three-page bulletized exec summary with real data in it for each of these subsectors, be it biofuels, or crude oil, what have you. And I think empowering industry to virally distribute those executive summaries will help in the CEC achieving its goal of sort or raising the level of dialogue. That is one. The second is an idea that really, I think the Air Resources Board has demonstrated quite well in its development of the Low Carbon Fuel Standard, which is really creating a roundtable environment where sectors can get together on an industrial basis, on a commercial basis, and have discussions amongst themselves under the auspices and under the guidelines presented by the regulatory body, in that case, the Air Resources Board. I think it would be interesting if the Energy Commission were to actually host, if possible subsector roundtable discussions of the final document and to see what kind of debate can actually be spurred. And I think that may very well provide enough impetus to get certain projects off of the back burner and on to the front burner.

So with that, I would like to just add a couple of thoughts which were not on the agenda about energy security technology and infrastructure. We heard earlier today about energy security and we heard that some of these policies may be promoting the importation of someone else's Ethanol over domestic gasoline, and all of these other issues, and that is all very important discussion to be had. I just wanted to point out that energy security is not necessarily a question of domestic supply, or domestic oil versus imported oil, it is really a question of functional competitive marketplaces. And the reality is that crude oil based transportation fuels have a corner on the transportation market in excess of 98 percent of the marketplace, and that does not give Californians, or anyone else in the United States, a real choice either at the pump, or when they buy their vehicles. And that is a lack of energy security. Creating an environment that is more competitive and give ultimately consumers more choices is energy security, irrespective of where those fuels ultimately come from. So that is one point on energy security. Second on technology, I think we heard some inconsistent messages, or internally inconsistent messages today that I would like to make comment on. We heard that there are lots of technologies to find more crude oil and explore it and develop it more sustainably, and there is no doubt about that, that is absolutely true and I would not contest that. But at the same time, there are a whole host of technologies to produce renewable fuels and renewable electricity, and so on and so forth, as well. And I think what we need to maintain here is an open mind, that indeed if we create marketplaces that are truly competitive, and rules that are understood, that you can create an environment much like the Low Carbon Fuel Standard is intended to create, in which there is real competition ultimately resulting in a real choice for consumers. Commissioner Boyd, you asked the question earlier, does the Low Carbon Fuel Standard provide a vehicle by which E85 might be adopted in higher concentrations in California. Now, I would submit, if the rules are created clearly and plainly and enforced properly, I would say absolutely. The Low Carbon Fuel Standard is simply an attempt to price in the externality of the climate crisis into every gallon of fuel and ultimately that should result in a price premium for lower carbon fuels. If that benefits Brazil in the short term, that is fine; ultimately, it will result in producers becoming more efficient, distributors becoming more efficient, and everyone up and down the supply chain worrying about their carbon footprint, which is precisely what this type of regulation is intended to do. The challenge now is, can California develop an environment in which the same embracement of change that has been occurring along the technology side, can happen on the infrastructure side, a world that is generally considered boring and old and made out of cement and steel and other boring stuff, no fancy new molecules and enzymes on that side of the fence? The reality is, is that I think the creativity and passion that has been harnessed in California to develop the technologies for fuels, and batteries, and so forth of the future, have to be fostered also on the infrastructure side of this equation. And to the degree that the Energy Commission can foster that kind of creativity, I think California will come out better for it, not only the policymakers, but the citizens more generally, and as a California native, I believe that quite strongly. So, in any case, thank you for that. My contact information is on the slide. Please have a visit of either one of our websites, or give me a call or an e-mail if you should have any questions. We fully intend to provide more detailed responses to the draft report in the coming days with a little bit more quantitative analysis. Thank you for your time.

VICE CHAIR BOYD: Thank you very much. Very interesting, intriguing, stimulating, even, suggestions. We appreciate it.

MR. IYER: Thanks.

COMMISSIONER BYRON: Agreed. Some good

recommendations. We will certainly consider them. Thank you for being here.

MR. IYER: Thank you.

MR. PAGE: Commissioners, we have had a request for an addition to the agenda from Southern California Edison, Felix Oduyemi would like to make a presentation if that is acceptable to you.

VICE CHAIR BOYD: Very acceptable. Now you eliminate from my conclusion, "Where is electricity?"

MR. PAGE: Okay, well, good.

MR. ODUYEMI: Good afternoon, Commissioner Boyd, Commissioner Byron, and those of us who have been here for the whole presentation. I am really really glad that you allowed me to speak. Thank you very much.

COMMISSIONER BYRON: Please introduce yourself.

MR. ODUYEMI: I am Felix Oduyemi, I am with Advanced Technology at Southern California Edison. I worked specifically as the Manager for Electric Transportation. My first observation when I read the report was that we did not develop electricity as a transportation form, but have since spoken to staff, that was just an early idea they are working on, they are going to be including electricity as a transportation form. So my original reason for being here is not as [inaudible], but I have other issues to cover.

You also have as part of this report, the overall report, IEPR, the Smart Grid. And we look at electric transportation as a component of a Smart Grid deployment strategy, so in discussing infrastructure, we have to discuss infrastructure in the context of not just having a plug -- I have a whole bunch of plugs around this room and, yes, I can bring my electric vehicle and actually plug it, and it will be able to work. But long-term, that is really not going to work for us because, if our projections are correct at Southern California Edison, we have about 16 percent of our penetration for electric vehicles, and may not be [inaudible] territory by 2020 will get by with electricity. So 16 percent, that constitutes about 11 percent of our load, it is a significant amount of load that we expect to devote to electric transportation in 10 short years. And so the generation aspect of the equation is not what we are concerned about, we are more concerned about the distribution, as well as renewable integration aspects of the equation, and those are the ideas that I would like to cover today.

When I look at transportation in the future, I look at this chart, and I look at my car, I can actually become an Energy Storage system that is not just providing energy to drive my car, but it can actually provide energy to my grid. But that technology has yet to evolve. So over time, we need the Energy Commission to help us with the necessary research to make this happen. We are developing some research for Energy Storage systems. We are also looking at the same battery that we have in that vehicle is going to be deployed at wind farms to become part of our renewable integration program. So this Commission is going to be very very instrumental in helping the utilities actually optimize utilization of resources, as we continue to deploy Smart Grid.

I will look at three key areas, and this is going to be my last slide. I have a whole bunch of them, but I am not going to go beyond this slide because we are running out of time. We look at three legs of this tool as we are thinking about deploying electric transportation into the grid, and I look at distribution system readiness, effective load management, and renewable integration. Those will be the three legs we have to consider as we introduce more electricity to become a transportation fuel. When we do research and we want to deploy public, for example, charging stations, there is a lot of debate with so many of my colleagues, what should this look like? And what will be the impact of that? I am more interested in the impact of that public charging infrastructure on my distribution grid because I still have to provide the electricity to my customers. And so if we deploy our own type of technology or we check the vehicles at your own time, it will probably cost you a whole bunch of black-outs, we do not want that to happen, and we do not want utilities to also have stranded investments, simply build an infrastructure that will not be utilized is really not a very wise use of money. So I take an electric car, you are going to have charging facilities in your house, and charging facilities in your workplace, and therefore, if you have level 1 or level 2 charging at home and at your workplace, the way you are meant to deploy level 1, level 2, or level 3 charges as public infrastructure. When you do your math correctly, we may find out that it pays for us to simply do level 3 charging when we consider public infrastructure because it should be able to charge whether it is 1, 2, or 3. You just want opportunity charging. I have not completed doing all the analysis, but we intend to do it. But at the end of the day, I am going to have in a city like Santa Monica a whole lot of electric vehicles and we want them to charge off-peak. We are going to be encouraging them to, before charging these vehicles, to later and later in the day. That way, we do not impact our existing peak at about 16:00 hours. Now, you get home and you start charging your car at 17:00 or 18:00 hours, and I have a spike in my system. You [inaudible] down the system if we do not develop the necessary communication system that will allow us to sequence the charging so that we can level our load. So we have to look at the electric transportation in terms of the communication technologies that we are required to allow us to spread out the charging of the load. We might bring more damage to our distribution system. So whether there is public charging, or workplace charging, or residential charging, we need to look at my column 2 in terms of the vehicle communications and standards that will be required to integrate this into our grid in a way that we can actually manage the load effectively, to help us to achieve a better load factor. I need to look at my computer systems in the back office to be able to do the right communication in terms of billing, in terms of moving electricity from the vehicle to the grid, or from the grid to the vehicle, or to do whole area network. So those times of Smart Grid technologies will need to be considered as we consider electric transportation and deployment. So I am not just here to tell you that we do not have adequate electricity -- yes, we do have abundant electricity, but we do not have adequate technologies to actually optimize the utilization of this technology and the utilization of the resources that we already are paying for as a state.

And I look at my third block of area that we are focusing on at Edison, which is the renewable integration. Since 1896, the difficulty we have had as a state, or as a country, is that electricity has no color, I mean, you turn it on, you have to use it, we generate it, and it goes. Today, we generate so many Megawatts of power, I do not want to say how much, from many windmills and those windmills, they operate 24/7, most of the time they do not generate much, but at night time when we do not need the electricity, they blow like hell, and now we have all this energy at night time, I have to sell them to some other sources for pennies on the dollar, and so if I am able to start that energy and actually deploy it as I need it, and I use the same technology that I have in the electric vehicle, I can make a bigger size of that, put it in my wind farm, start the energy, and then put it back into the grid at 4:00 p.m. when I actually need the power. It makes a whole lot more sense; however, we are going to need the Energy Commission to help us plead the case that renewable integration into the Grid should be considered a compliance option when we look at RPS compliance. Today, we are 20 percent requirement by 2010, we may be going to 33 percent by 2020, we are not sure yet, I know there are a lot of Bills in the Legislature requiring that, but if we can do better by integrating battery technology or other energy saving technology, NIG storage technologies, into renewable generation assets, that way we can then count the useful generation, not just generation that we produce and we just allow to go to waste, they would count it as meeting our renewable standard. I know I have so many other slides I would have loved to show you, but I will not waste my time on that, but if you can bear with me, by 2015, this is our projection in our service territory, and we did a lot of scrubbing of this data. I am expecting about, oh, 160,000, maybe 161,000 plug-in hybrid electric vehicles and about 77,000 BEV's by 2015, that is just six years away. If I allow all of this in my system without the necessary communication technologies to allow me to shift the load in a way that it will not bring my power system down, we will have some challenges. We do not want to have those challenges, and we are going to need your help to work with the CPUC to allow us to send the right price signals to our customers so that, 1) they will be allowed to charge off-peak, give them special rates for charging off-peaks, but also give us the control so that we can manage the load in a way to optimize utilization of our Grid. Thank you very much.

VICE CHAIR BOYD: Thank you, Felix. I really appreciate you pushing the point and getting on the agenda. Just last week, Felix and I were at the plug-in hybrid electric vehicle symposium conference in Long Beach, and extensive discussions of some of the subjects you heard here today. This agency created and sponsors a plug-in hybrid electric vehicle research center at UC Davis, it has a research committee advisory to that group in which we discuss a lot of these issues -- Smart Grid, the secondary use of vehicle batteries for this energy storage question that is coming up, and Commissioner Byron and I, being the Electricity and Natural Gas Committee, have had lots of discussions in that committee forum on energy. All of this integrates together as part of the system that has to support whatever forms of transportation and electricity we have in the future. So your point is a very good one. We will certainly take into account all of your slides and we definitely will have electricity in the final report as one of the major alternative transportation fuel sources for the future. So thank you for being here.

MR. ODUYEMI: Thank you.

MR. SCHREMP: Good afternoon. I am Gordon Schremp, Energy Commission staff. I have yet another presentation. Not as many slides, this is my first one, I will go a little bit faster.

The subject matter is, instead of renewables, it is traditional transportation fuels, petroleum-based gasoline, diesel, and jet fuel, and our analysis and outlook on what we see as both exports of petroleum fuels to the neighboring states of Nevada and Arizona, via pipeline, as well as imports of each said fuels, via marine vessels and marine importing infrastructure. Or, as the case may be, marine exports from our analysis.

So we are an, I guess, integrated system, if you will, interdependent. California is essentially like a hub on the West Coast. We are the predominant supplier to Nevada and now a little bit less of a supplier to Arizona due to some changes, additional supply from the east. So we went through sort of a stepwise set of analyses to determine what kinds of changes in our trends for both pipeline exports and marine imports may occur over the forecast period. So, first of all, we do some demand projections for Arizona and Nevada, that is because we supply fuel to those states via pipeline. Secondly, we then determine what level of pipeline exports will go to those states from California. Well, Nevada is pretty simple, there is only potentially one pipeline at this time to Northern Nevada, and one pipeline or a couple pipelines to Southern Nevada. But Arizona is supplied from two different directions, so we make some assumptions in there, and I will talk about that in a little bit. Third is, we assume some level of refinery production change due to "refinery creep," Mr. Sparano's favorite term, and we only have that in one of the cases this year, the same in their crude oil assessment that refineries over time will process a little bit more crude oil moving forward, as they have done so historically. And then, finally, looking at our demand projections, and I used the revised gasoline demand projections, not the initial ones, Malachi, of percent, but the ones that are impacted by RFS2 compliance, so they are lower than Malachi's number. And so we look at how all of that works out over time in changing the level of imports that have come through our marine terminals.

So this is the Southwest system of Kinder Morgan, and just to highlight the two pipelines going up into Las Vegas, some [inaudible] system, there is a project for a third line that has been permitted, and I will talk a little bit about that. And then we have the main west line that goes all the way into Phoenix, and then there are essentially two lines that come in, the one terminating in Tucson, the other carrying all the way into Phoenix from the East, supplied by refineries in West Texas, and even refineries in the Gulf Coast via the Longhorn Pipeline connection to the East line. So how do we figure those out? We assume that there will be a resurgence of demand, jet fuel, gassing, diesel, after the U.S. long recession comes to an end and some economic recovery does occur, so we do see some demand growth coming back, especially for diesel and jet fuel, as is the case in California. And we think that there will be additional exports via the pipelines. There is one scenario we did examine, and that is a new pipeline originating in Utah, and terminated in North Las Vegas. That is the UNEV pipeline, and that will reduce the demand for pipeline exports to Nevada, and I will show you what that looks like. So like I said, Nevada, about 100 percent comes from product originating in California or passing through California on into Nevada. Arizona, though, has been changing the amount of fuels coming out of California, about 55 percent in 2006, but dropping down now to 35 percent in 2008. Well, that is because the east line expansion was completed, additional product was flowing in Longhorn pipeline, and coming all the way from Houston into Western Texas, and connecting to the East line. So that tells us that the marketplace supply options, economics of pipeline delivery, and timing were such that the market wanted more product to come from the East, rather than the West. So we believe that when the system gets back to a more normal circumstance, and I mean part of that system is, as you are well aware, Flying "J" declared Chapter 11 right before Christmas 2008, part of that business changed and restructuring -- the changing hands of some of these assets, one of them is the Longhorn pipeline, which I believe has now moved into the hands of Magellan, and someone can correct me if I am wrong. So we believe that, going forward, that the Longhorn pipeline will have sufficient capital to resume more normal operations and maybe even increase the amount of fuel coming from Houston and going into West Texas and into Arizona. So time will tell, certainly.

So we look at these systems and we made certain assumptions about which direction the product will come from, and we think there will be a preponderance of product coming from the East side, into Arizona. So the benefit, if you will, of reduced pipeline exports from California is what we refer to as "indirect supply," well, that means the refiners, for example, have more blending components they can use to produce California gasoline, rather than Arizona cleaner burning gasoline, or Nevada, LVBOB, so that is, I think, good for supply perspective. There certainly has not been a need for that with the tremendous drop in demand for both gasoline and diesel fuel in California, so there has been a respite, but at the same time, having said that, there has been the loss of a refinery, and that is the big west of California, a Flying "J" subsidiary that is now idle because of these Chapter 11 proceedings. So a refinery is not operating, that is a loss of supply, but only because of the big decrease in demand for gasoline, diesel, and jet fuel that the system has been able to accommodate rather easily this time, but we anticipate that that refinery is going to come back in operation some time in 2011 at the latest, in our analysis.

So what does the demand look like in Arizona and Nevada? Well, this time through, for both -- for jet fuel, we used the most recent FAA forecast, and these are enplanement activities, passengers boarding planes, by individual airports. So using those enplanement forecasts for the Reno, McCarron Airport, Las Vegas, Arizona, Tucson Airports, in conjunction with changing fuel economy improvements in moving people via jet and freight, we have come up with demand forecasts for jet fuel that shows an increase over the forecast period, and we only use one jet fuel demand trend, we do not have a low and a high. Diesel fuel, we have a low and a high, similar to -- we use, in fact, the exact scenarios from EIA in their annual energy outlook that we used to look at their gasoline demand forecast to make with ours when we did an RFS2 calculation. So those pairings, if you will, we used for diesel fuel and for gasoline, and we used that portion of the country, which EIA does break out, they have a forecast for individual census districts of the United States, and so we used those trends to apply to a 2008 actual, moving forward through the forecast period of 2030. So that is how we generated those numbers, both in a low demand side, and a high demand side. And that is for total demand in the state, recognizing that not all of the product to Nevada and Arizona is delivered via pipeline. So we started with what we believe is their total demand numbers for 2008.

So here they are for Arizona, and you will see that basically the highlights here are gasoline in the low demand, and once again, this is the EIA low demand case, this is essentially flat, 2020 and 2030, .1 percent increase, .8 percent decrease. So that is essentially flat. In the high demand EIA case, we see much stronger growth, almost 32 percent by 2030. On the, I guess on the diesel side, we see that there is very strong growth, and then you take the grand totals of all the fuels and you will see anywhere from 30 to 54 percent by 2030, either a low or a high case. Now, important to point out that, as we did with the gasoline forecast in California, the gasoline demand forecast for Arizona and Nevada, on the next slide, were adjusted downward to compensate for the Renewable Fuel Standard Part 2, and that is resulting in increased amounts of E85 in this column, and displacing E10 gasoline on sort of an energy equivalent basis, moving forward over the forecast period. So same thing here -- more E85 than currently is going on, a lot more in Arizona than in Nevada, and a bit dampening of the gasoline demand forecast. And as is the case with California, we have assumed an E10 cap on the low level blends, recognizing that certainly Arizona and Nevada may have some opportunity to go to an E15 blend that California does not have over the near and mid-term, but for purposes of analysis, we assumed an E10. If there was an E15 cap for low level blends, then the number of the E85 blends would be smaller than they are in this forecast.

Nevada is very similar. The numbers are a little bit higher because, once again, we are using the same -- or, excuse me, the percent increases are a bit higher, they are not identical, because actually the jet fuel demand growth in Nevada is greater, growing at a greater rate than that of Arizona.

So now, how does all of this play out with additional pipeline exports? Once again, for the low case, we are seeing that there is an actual decline in gasoline exports to the neighboring states, both Arizona and Nevada, but we are seeing overall an increase because of the diesel and the jet fuel of anywhere between 37 and 22 percent over the forecast period. So still growth, so this is sort of a total demand poll on California source product, or product moved into and through California. High case, significantly higher, doubling basically by 2030 for Arizona, and 41 percent increase for Nevada. So we are still showing growth in the pipeline sourced from California, and this is -- bare in mind, we are assuming that the pipeline exports from the East because Arizona has that flexibility, get it from the west, get it from the east, we are assuming the east pipeline shipments take priority, meaning they fill that system up first, which is assumed it is 2015, and then operate that capacity and then continue to use the spare pumping capacity in the west line up through the forecast period.

So do we see using these assumptions and these growth rate assumptions and analyses, do we see constraints in these pipeline systems? And the answer is essentially no, not over the forecast period. That is because demand has come off so much and now the new, latest forecast in this IEPR cycle, are a lot less than they were in the last IEPR cycle two years ago. The one exception here to be noted is in the pipeline system, Colton to Las Vegas, the CalNev System, we are showing that there would be a bump up to a capacity limit in 2021 in the high case, and 2026 in the low case, but that is easily addressed since Kinder Morgan already has a project essentially approved that they have now deferred moving forward by spending capital and actually instituting the construction, because they do see a drop in demand, and no reason to do that. Now, take it a step further, if in fact the pipeline project scenario I mentioned coming out of Utah is actually constructed, then this kind of expansion of the Colton to Las Vegas system would not be necessary because there will be additional capacity out of Utah -- assuming there is supply.

So refinery operations, as I mentioned, that is part of our analysis, we assume, yes, there is some continuing growth in the amount of crude oil processed at the refineries. That is their processing capacity. How much crude oil will actually run through their refineries will never be at 100 percent because they have to do maintenance on these crude units, so it will be some level less than 100 percent utilization rate of that capacity, and we are seeing that the capacity numbers have come down recently. There have been some heavier than normal crude oil maintenance work and there has also been, you know, a running of the refineries a little bit less, lower utilization rates, because the margins were poor at times. And, yes, that is more like 2007, not 2008 for decent gasoline time, so we understand that. But there has been a recent trend of a sort of downward utilization rate. But we are assuming a utilization rate of almost 90 percent over the entire forecast period. Now, when you process additional barrels of crude oil, we assume that the ratio of products you are making at the refinery from those additional barrels of crude oil being processed would be similar to what they were in 2008. We clearly recognize that refiners have the capability to adjust some of these ratios of either distillate, or jet fuel, or even some of the gas in how they blend some of the gassing components, so they would have different ratios than those presented here. But for the sake of our analysis, we are assuming that these ratios are held constant throughout the forecast period. So any time we see more crude oil, we will get more products available for use in California, as well as export, in these ratios.

Now, I want to point out, as I did in my initial presentation today, this chart is slightly different than the one that is in the report, and this is the correct chart that we will be using in the revised document. I just want to point out that these numbers are a little bit different than what you saw in the actual staff document. So looking at a low import case, we go, how do you minimize additional imports? Well, one assumption is that the growth rate for additional crude oil processing is not the low import case, produce more products, do not have to import as much, and a low demand case. So the purpose of this analysis is to bracket the amount of import growth to a low side and a high side, and as you will see soon, the bracketing actually results in an increase in exports, and I will talk about that. So we only have one scenario of refinery creep, and that is in the low import case, and we have no refinery creep, or level distillation capacity in the high import case. This is the same that we did for crude oil assessment.

So as you will see in just a moment and in this bullet, the low import case actually results in California exporting 250,000 barrels per day, by 2015, of gasoline.

Now, you might say that is a lot and, yes, it is, it is about a quarter of what we use now, so we would turn into a very large exporting hub, something like the European refining community. So we do not think that is going to happen, this is just an artifact of how we have set up this analysis and we will show you why we do not think that will happen, and what they will do. So we think there is something that they can do, and one of them is eliminating gasoline blend stock imports, another is actually reducing the amount of partially processed crude oil, or unfinished oil that they obtain from outside the refinery, and they help make a lot of their refineries to produce additional gasoline, and some diesel fuel, without processing anymore crude oil, so they do today.

This complex set of charts, and yes, I do not have as many pretty pictures as last time, these are more tables, but that is how we have set it up. This is showing you the initial numbers and you are seeing that these were basically sort of the net imports in 2008, 51,000 barrels a day on average of gasoline. We were a net exporter of diesel fuel, we were long in diesel fuel and it was being exported over the dock. Jet fuel, we were a slight net exporter, we were usually a large importer, but jet fuel demand was down significantly. So total, basically a net exporter over the marine docks. Now, net change is rather dramatic for gasoline, net importer to a very very large net exporter, do not think that is going to happen. High import case looks a bit more reasonable, you get into slight less imports by 2015, but then into a net exporter. So once again, would the refineries continue processing as much crude oil, or even increasing that, and having more and more excess product to export? No. We do not think they would do that. So the first change is you eliminate those imports of gassing components, and so you change the impact so you are not as much in balance in gasoline, and you fix the imbalance in 2020 in the high case. Same thing, you just take it a step further, you go, "Well, I'm not going to purchase unfinished oils and stick them in my fluidized catalytic cracking unit, I'm going to not do that," and then I reduce the gasoline imbalance further, actually eliminating it in 2015, and still having a very large imbalance by 2020 and 2025.

So, I guess the short story is that, unlike two years ago, we were showing continued growth in California demand on all fuels and its subsequent growth in imports; now, because of the very low gasoline demand outlook, we are seeing an imbalance develop in the refining sector that we do not think will stand, we think they will make some adjustments. The final adjustment to make, of course, would be the closure of some refinery assets, or even the reduction in the amount of crude oil being processed, or their utilization rate not being 90 percent, but maybe being 85 percent, 80 percent. And that change would reduce the demand for crude oil imports. And we have not looked at that because these two changes are only adjusting gasoline blending stocks and unfinished oils, not crude oil. But that would be a third change to make.

Just to touch on that pipeline from the Salt Lake City refining complex up here, this is a pipeline that goes all the way to the North Las Vegas suburbs, that would be designed to bring in 62,000 barrels a day of petroleum products as early as next fall. The pipeline capacity has an upper limit of 118,000 barrels per day and, once again, both of these assume there has to be incremental supply available to move from the Salt Lake City area, down to North Las Vegas. But that kind of pipeline actually being constructed and coming online would dramatically reduce the amount of products coming into Las Vegas, the west, at least to have the ability to reduce them. Obviously, there would be a competition between that pipeline system and the west line, and Las Vegas would like to see that kind of competition, I am sure.

So how does that scenario change the imbalance? Well, it makes it worse, obviously, because more product available in California because now it is being displaced on a product coming from Salt Lake City. So these imbalance numbers become very large, so there will be even more excess supply in California according to this forecast. In the high demand case, a bit of total -- become a big of a net exporter in the region versus a net importer in the high case. And then we remove that assumption that, "Oh, yeah, the refineries will process a little bit more crude oil," there is not any refinery creep in either the low or the high case, and so this only impacts the low case estimate -- low import case estimate -- and we see a reduction from these numbers, down to these lower bars down here. So, almost 140,000 barrels a day less of an imbalance by 2025. So one final note on this slide, we did not look at any refinery expansion projects, an old Chevron Richmond project that recently ran into some EIR difficulties with their project there, they had a hydro cracker, I guess, replacement essentially that was going to increase gasoline production by 7 percent, they have made statements that they are not going to move forward with that project because of the downward decline in demand. So we do not think there are any other refinery projects that we are aware of to increase local supply at this time, and that is likely because of some poor economics, as well as near term trends of downward demand. And that concludes my presentation. I would be happy to take any questions.

COMMISSIONER BYRON: Commissioner Boyd, not having served with you on the Transportation Committee for more than a couple years now, what a change.

VICE CHAIR BOYD: Yes.

COMMISSIONER BYRON: Some dramatic changes as a result of the downturn in the economy, and new pipelines being built, it is not quite the same picture we saw two years ago.

VICE CHAIR BOYD: No. I agree with you. I do not have any other comments on this presentation.

COMMISSIONER BYRON: Nor do I, Mr. Schremp. Thank you very much.

MR. SCHREMP: Thank you for your time.

MR. EGGERS: Good afternoon, Commissioners. My name is Ryan Eggers. I am an Energy Commission specialist in the Fossil Fuels Office. I am here today to present the staff import crude oil forecast.

To jump right in, California refineries import crude oil to make up the difference between California's own domestic production and the inputs needed to satisfy the demand for their products. As seen in this figure, U.S. crude oil production has been on the decline since 1986. From 1986, when U.S. crude oil production peaked, until 2008, California crude oil production has declined 41 percent, Alaskan crude oil production has declined 61 percent, and the rest of the United States has declined 36 percent. This represents a 57 percent decline in U.S. crude oil production as a whole over that same time period.

Looking more specifically at California crude oil production, California has for the most part gotten its crude oil from onshore sources. These sources, the top five producing oil fields in 2008, were all in Kern County. Offshore production peaked in 1995 and most of that offshore production occurred off the Santa Barbara County coast. And more long-term perspective of California crude oil production shows that California has been producing oil since the mid-1800s. During that time, it peaked in 1985 at 424 million barrels and has steadily declined ever since. On a more interesting note, if you sum up all the production of California crude oil from the mid 1980s until today, it would only sum up to about 93 percent of global oil demand in 2008.

Here are some of the current trends in crude oil production for 2008, namely global crude oil production was 31.7 billion barrels in 2008; U.S. crude oil production was 1.8 billion barrels in 2008, which was only 5.7 percent of global production; California crude oil production in 2008 was 239 million barrels, this represented 13 percent of U.S. production, but was only three-quarters of 1 percent of global production.

Staff would also like to note that the decline in crude oil production for California, just demonstrated in the previous slide, is expected to continue into the future, as well as U.S. declines, most notably in Alaska.

Because of these declines in crude oil production, imports in crude oils have steadily increased to fill in the production gap. As seen here from the early 1800s to the mid-1990s, Alaska provided the bulk of import crude oil to California refineries. Since the mid-1990s, foreign crude oil has become an increasing portion of the import crude oil portfolio, and has become the majority since the early 2000s. To put more specific numbers on these trends, total imports in crude oil have increased 24 percent since 1998 to 2008, imports of Alaskan crude oil has declined 60 percent during that same time period, and because of that, foreign crude oil imports have picked up the slack by increasing at a rate of 11.7 percent a year. With those increases, foreign imports of crude oil are three times larger than their 1998 amounts. So, using these trends previously demonstrated, we hope to flesh out the outlook for imported crude oil in California to 2030.

The approach used by staff in order to calculate future import values was pretty simple in its conception. First, we make a forecast on the refinery distillation capacity to 2030, then we also make a forecast for the

California crude oil production side, taking the difference between these two forecasts gives us a crude import forecast value, which we can then make infrastructure requirement calculations based on.

This slide displays the staff forecasts for crude oil imports to California refineries. These forecasts assume that all 20 California refineries will be operating at a utilization rate of 89.9 percent of maximum capacity throughout the forecast. I would also like to note that these input forecasts assume the recently closed Bakersfield Refinery will be open by January of 2011, and no new refineries will be opened. By assuming these two constraints, the general increase in refinery capacity known as "refinery creep" becomes the difference between the two forecasts. In the high refinery case, we assume a refinery creep value of .45 percent, and in the low refinery input forecast, we assumed no refinery creep. Of note, the difference between these two lines in 2030 will be 68.9 million barrels.

On the California crude oil production side, recent declines in crude oil production has led staff to forecast two declining production forecasts. In the high decline scenario, we assume a 3.2 percent per year decline in crude oil production. This value was arrived at as a 10-year average of the historic decline in crude oil production for California. In the low production decline scenario, we assume a declining rate of 2.2 percent per year, this was the most recent three-year trend within crude oil production.

By putting these four lines together, namely the high refinery input forecast with the high production decline scenario, and the low refinery input forecast with the low production decline scenario, yields are high and low import forecasts. Here is the low crude oil forecast, along with historic numbers for refinery inputs and crude oil production. Using the low refinery input forecast and the low production decline scenario, staff finds that crude oil imports will grow from the 2008 level of 406 million barrels to 440 million barrels by 2015. Under this forecast, imports will continue to increase to 461 million barrels by 2020, and 497 million barrels by 2030.

In the high California crude oil import forecast, which uses the high refinery input forecast and the high production decline scenario, staff finds that imports will grow to 476 million barrels by 2015 to 519 million barrels by 2020, and to 596 million barrels by 2030. It should also be noted that these relatively small changes in both refinery input and crude oil production will result in higher import. Crude oil forecasts require almost 100 million more barrels than the lower forecasts.

To recap, staff believes that crude oil imports will continue to increase to 2030. This increase is primarily a result of declining California crude oil production and in the high import forecasts, increases in refinery capability. The low import forecast uses a production decline rate of 2.2 percent per year with no expansion in refinery capability. This produces an increase in crude oil imports of 22 percent by 2030. In the case of the high import forecast, it uses a production decline rate of 3.2 percent with expansion of refinery capacity occurring at a rate of .45 percent a year. This forecast yields an increase of imports of 47 percent by 2030.

Using the two increasing import forecasts, staff has then calculated the additional yearly tanker visits that will be necessary to meet additional crude oil import needs. Seeing the figure on the slide, staff assumes that both the cargo capacity of both VLCC and Aframax vessels will remain constant over the forecast period. These values are shown by the bars on this graph. Additional tanker visits are indicated by the ship icons on the figure. The low forecast for additional tanker visits is produced by using the incremental crude oil import figures from the low import forecast, and dividing it by the VLCC cargo capacity. This low forecast has an additional 17 tanker visits per year by 2015, and an increase of an additional 46 visits by 2030.

For the high additional tanker visit forecast, the incremental crude oil import figures from the high import forecast was used, and was then divided by the Aframax cargo capacity. This forecast estimates an additional 100 visits per year by 2015, and an estimated 272 visits per year by 2030.

Giving the staff forecast of increasing crude oil imports and increased tanker visits, additional storage tank capacity for marine facilities serving the oil tankers will be necessary. Staff first assumes that the existing storage infrastructure is near or at maximum capacity, therefore, by using the incremental crude oil figures from the low and high import forecasts, two separate cycling rates were applied to those figures to calculate the low and high estimate. For the low estimate, a one million barrels of storage per 23 million barrels of imports was used. This type of throughput is similar to that estimated for the proposed Berth 408 Project. It is applied to the low increment of oil import figures. The second cycling rate is a 1 million barrel per 12 million barrels of imports and assumes that the new infrastructure will be working at a rate roughly half that to the Berth 408 Project. This cycling rate was then applied to the high incremental crude oil figures to generate the high storage tank estimate. Using these methodologies, staff expects additional storage tank capacity to range between 2.4 to 9.5 million barrels by 2020, and to 4 to 15.9 million barrels by 2030. Staff also estimates that the majority of these facilities, about 60 percent, will have to be built in Southern California to accommodate this need.

As in all forecasts, there are many uncertainties that can alter their outcomes. Here are two items that staff deemed were most relevant to the discussion, the first being, can crude oil production decline be halted, or even reversed due to technology advances or expanded access to offshore reserves. From a resource perspective, the answer is yes, there are offshore resources which I will talk about in the next three slides. Also, technology is always improving, which lowers the price of retaining resources that are currently economically unavailable, which could alter the forecasts, but these advances are hardly steady or predictable phenomenon. Next, will new crude oil import facilities be completed in time to maintain the inadequate supply of crude oil to California refineries? The Berth 408 Project is expected to relieve most of the near term needs of marine infrastructure, but there are no new projects that can account for the forecasted long-term infrastructure needs.

With regards to California crude oil production, the first item I would like to talk about is the possible expansion of crude oil production in federal outer Continental Shelf waters, or OCS waters. On October 1^{st} of 2008, Congress took no action to reinstate the moratoria on drilling in these waters. This opened up the possibility of increased crude oil production off the California coast. MMS has estimated that there are 5.8 to 15.8 billion barrels of undiscovered technically recoverable resources existing off the California shore, of which half are in federal OCS waters. They have estimated that between 53 to 73 percent of those are economically recoverable under a crude oil price ranging from $16 per barrel to $160 per barrel. This said, development of these areas cannot occur until a five-year program and a planning for specific sale process has been carried out and approved. These processes combined can take 3.5 to 5 years to complete. Absent any complications including litigation and other complications, EIA estimates indicate it could take even 10 years. Assuming that the moratoria is lifted, staff then used Department of Energy estimates of the new crude oil production coming from these areas. The DOE forecasts presented here and in our staff report assumes that production from the moratoria areas will begin in 2015. Seventy-four percent of the total increased production from these areas is forecasted to originate in California OCS waters. While a significant amount of crude oil could be produced from these fields, with the forecast in crude oil field decline rates from existing fields, the new OCS oil production is likely only to offset those declines. Even under the low incremental import forecasts, imports could only be shrunk by 36 million barrels a year by 2020 from their 2008 totals. Under the high import forecast, crude oil imports would rise by only 37 million barrels by 2030, but not as drastically as the status quo scenario in the high import forecast of 191 million barrels.

Given that any federal OCS project would not be in effect any time soon, there is only one project that staff knows that could increase short-term production. This is the Tranquillon Ridge Project, which is a Plains Exploration and Production Company Project that involves drilling of additional wells from Platform Irene, off the Santa Barbara Coast. It has the potential to begin generating additional crude oil within one year of approval and estimated to reduce 2.9 to 9.9 million barrels a year until the sunset of operations in 2024. But currently, as far as staff knows, the status of this project is in doubt, given its failure to win California State Assembly approval last July. This concludes my presentation. Are there any questions or comments?

VICE CHAIR BOYD: Well, first, I would say it was a very good analysis, however, well, enough said. But the however goes to assumptions and uncertainties that you correctly identified. I, for one, question the likelihood after slaving away here with some of you for seven and a half years of trying to get additional storage capacity in California, and secondly, venturing out into the California OCS is an interesting experiment, and there is a history in this state that goes way beyond my years here, it goes back to the spill that Mr. Sparano referenced this morning, and that is tough territory to get into, so if I was planning California's future, which I guess we are in a way, I am kind of skeptical about us getting at that resource, but it is a very interesting analysis. As others have said, there is a lot of interesting and good analytical data in what you have done today. Anyway, those are just thoughts, no comment necessary.

COMMISSIONER BYRON: Mr. Eggers, if I may, I want to make sure I understand the forecasts that you are doing, the low forecast, high forecast, I am looking back at slides 11 and 12, for instance --

MR. EGGERS: Perfect.

COMMISSIONER BYRON: I hope I am not showing my ignorance of this question, but do these factor in the Low Carbon Fuel Standard and/or the Renewable Fuel Standard 2 requirements into these forecasts?

MR. EGGERS: No. These forecasts only take into account keeping current California refineries operating at the 98.9 percent, so regardless of what is happening on the demand side, we are assuming that California refineries will be operating at the same rate into the future.

COMMISSIONER BYRON: But you have one problem, if you have a rule or a standard like this, do we really care what capacity the refineries are operating at? Wouldn't we rather see the forecasts based upon the implementation of the standard?

MR. SCHREMP: Well, if I may, Commissioner Byron, this is Gordon Schremp, I will just go back to your previous question. Our forecasts for all transportation fuels do account for a Renewable Fuels Standard Part 2, and as I was trying to illustrate in my previous work, we believe that results in a large imbalance that can be corrected by the refineries not importing blend stocks for gasoline, and then not using as much unfinished oil, such that they have addressed the RFS2 and neighboring state needs, and the total downturn in California's gasoline demand, without adjusting these crude oil input numbers or forecasts. To take it a step further and actually say they will run at lower crude oil rates because of maybe some other potential implications of the Low Carbon Fuel Standard, even backing out more gasoline, that is certainly possible, and then it would start to affect these forecasts. I think the crude oil forecasts that staff has worked on have incorporated the impacts of the RFS2 such that they do not appreciably impact crude oil import forecasts as we have analyzed. We would have to go a step even further than that, and that is to reduce the crude oil they are operating in refineries from some impacts of the Low Carbon Fuel Standard that we have not yet portrayed because of the level of uncertainty associated with that regulation.

COMMISSIONER BYRON: Well, I am not going to waste everybody's time, but I am not sure I am following you there, Mr. Schremp, so we are going to have to discuss this some more.

MR. SCHREMP: Okay.

COMMISSIONER BYRON: Let me ask you, on slide 14, these low and high forecasts and the additional tanker visits, is there any consideration of whether or not the ports are going to be able to handle anywhere from 50 to 250 additional visits per year in 2030?

MR. EGGERS: Gordon?

MR. SCHREMP: We do not anticipate a problem handling this increased -- we are not handling them, we are not Stevedores or Harbor Pilots, but the industry and the complex to handle these vessels should be sufficient, keeping in mind that the ports are multi-use, and the lion's share of the vessel activity, or potential congestion is from the cargo container vessels. A massive amount of cargo container vessels ply these waters, especially Port of Los Angeles, Port of Long Beach, so as a fraction of vessel activity, if you will, the petroleum base, both crude oil and petroleum products, is a much smaller subset. So, yes, these even on the high side, say one additional vessel visit per day, yes, that is a lot more than today, but in the grand scheme of total vessel visits, it should be handled, and a secondary point is that they are designed to go to a specific destination within the port, especially in Southern California, a new berth, so a new space for them to actually tie up to, that would be Berth 408 -- if that does get approved.

COMMISSIONER BYRON: Okay.

VICE CHAIR BOYD: I do have a question and it relates to Alaska, and for years everybody talks about in documents the import of crude oil in decline, and it is pretty generally presumed by most that the North Slope is in decline. And I have no -- well, I was going to say I have no basis to challenge that, yet I found it interesting this past spring to have a lengthy discussion with a major North Slope operator, who talked about their plans to invest an incredible amount of money in the North Slope, in terms of the facilities are old and need a lot of R&R and what have you, and that they are planning on operating up there for at least 50 more years, and I did ask the obvious, "You mean there is oil to be had?" And they feel, yes. So --

COMMISSIONER BYRON: There is money to be had.

VICE CHAIR BOYD: Well, yeah, I just do not know if they are presuming $140 barrel oil, or we will pay for that investment, or what. I thought it a curious situation. And I do not know if that is a question or not. I do not know if you have any different data, or information, or an answer to why people would be wanting to do that, unless -- kind of like pumping that heavy crude out of California, it just keeps coming even though it is theoretically almost exhausted some times of the year.

MR. SCHREMP: Commissioner Boyd, I think you are right, there have been some real recent changes in Alaska production, the decline rate does seem to have slowed a little bit, there has been more activity and there are more plans. Certainly, $140 crude oil does merit additional plans being brought to Management about what one can do up there, and so, yes, that is not a surprise. So, sure, the decline rate in Alaska could be slowed, even arrested. That is a possible. But I think for purposes of our additional imports of crude oil, it has no impact whatsoever because we are looking at water borne imports of crude oil, so I guess we are in different -- because if it is coming from Alaska, or Saudi Arabia, it does not matter, it is coming in a marine vessel. And there is some merit to the size of the marine vessel and how many additional trips, whether it is a very large crude carrier of VLCC or an Aframax vessel, so there can be some incremental vessel visits that could change if we see Alaska crude oil being around a lot longer than maybe we anticipate. But for all intents and purposes, it will not change the volume metric increase in crude oil that would be necessary because of California's continuing crude oil decline.

VICE CHAIR BOYD: And presuming the California demand for finished product, thus crude oil, goes where you project it to go. Okay, thank you.

COMMISSIONER BYRON: Thanks, Mr. Eggers.

MS. GREEN: Commissioners, that concludes our staff and stakeholder presentations. We can now move on to the public comment session if you wish.

COMMISSIONER BYRON: All right. Mr. Eggers gets credit for keeping us on time. I do not have any blue cards, so I think what we will do is we will just solicit comments and questions at this time. We will start with those that took all the trouble to be here today.

MR. PAGE: We do have one request to speak from Michael Redeemer.

COMMISSIONER BYRON: Michael Redeemer?

VICE CHAIR BOYD: Michael Redeemer.

MR. PAGE: Oh, I am sorry.

COMMISSIONER BYRON: Who is not here.

VICE CHAIR BOYD: Who is not here.

MR. BRAEUTIGAN: Should we wait?

VICE CHAIR BOYD: If you have a question, ask it while we wait, before we turn to the phone.

COMMISSIONER BYRON: Please identify yourself.

MR. BRAEUTIGAN: My name is John Braeutigan. I work for Valero Energy Corporation. I had a couple questions and some comments. To save time for responding to my questions, maybe the staff could just view them as information requests. I had -- they did a great job, first of all, of putting out a lot of data. The questions are more on the projections of VMT coming along where they showed the historical data. This is mainly for the gasoline demand, and the diesel demand, and somewhat for the jet, if we could see what numbers were then used in the forecasts going forward for the base VMT or like the freight they are saying -- freight traffic has dropped off in the Los Angeles Harbor, that would be useful. The other one was, apparently, my understanding, the 2007 base case, they then took a plus X percent demand, I forget the number, and a minus X percent demand. We could argue or have our own theory, we would take an econometric model, hopefully, knowing the price elasticity of the fuels, which nobody knows exactly, you could give a realistic spread of prices and have a realistic spread of demand, but what would really be important would be to know the exact assumptions in that base case to 2007. For instance, whether -- and apparently -- the RFS2 meeting that obligation is not in there, and whether what assumptions were in there for future vehicle efficiency -- was Pavley in there? Was Pavley 2 not in there? Just because, if you are going to start doing things which Gordon did, which was great, saying, "Okay, the RFS2 compliance was not in a base case, let's add that in and see what happens," obviously you do not want to add in something twice. So it would be nice to know exactly what is in there for the assumptions of future policy decisions like vehicle miles because of Pavley, or federal. For the -- I would be curious to know what the staff was looking at, at the magnitude of shift between gasoline and diesel, refineries are limited as to how much they can shift. And then just two comments, one on the blend wall -- please remember, there are two blend walls and each are multi-layered. If you look at the gasoline blend wall, you have the 10 percent limit because of sub-sim for the U.S., or the CARB model, that is your first layer, your second layer is the warranty issue, both original equipment manufacturers and extended warranty companies. The third layer is just having the vehicles, depending on the result of whether warranties are extended or not, having newer vehicles that could handle a higher Ethanol level, and then the fourth layer is funding the infrastructure at the retail level, how do you ever get that accomplished, and getting around, obviously, the Catch 22 situation between the last two. The same layers are really there on the diesel side, too, where Gordon did a great job pointing out where we are not really sure how you are going to get all that E85. If you look at the curves, just the number of vehicles required, I would question, is that really -- what he pointed out was good data, that is what is required -- begs the question, is it really achievable? You know, does common sense say we really can ramp up that fast? Same thing for diesel, though. There is a B5 blend wall because of the warranty issue. You do not have the sub-sim, you do not have the CARB, but you still have all the other layers of the gasoline blend wall actually operating on a diesel, too, and if you have the Low Carbon Fuel Standard saying, "We want 10 percent in diesel, 10 percent in gasoline, and a B5 keeps you from obtaining 10 percent in diesel, that means you have got to get even more in gasoline and now your scenario starts to become even more -- maybe less probable. I have been working in this industry for 30 years, I have never seen a time when there was so much uncertainty. And staff has done a good job. It is really hard to predict. It may be nice to see a couple additional scenarios where you are looking at like the EIA has taken and said, "We do not think the RFS2 can be implemented at the schedule laid out," and they had a lower amount of cellulosic Ethanol going in, based on their assumptions of how fast cellulosic biofuel would come into the pool, that maybe you could call that common sense or a more likely case, but those are my comments. And the data requests, I will write them down and pass them on to the staff. That would be helpful to have a little bit more background. Thank you.

COMMISSIONER BYRON: Thank you. And before you come up, I was just looking to see if staff would respond to any of these. I tend to agree with the first comment that I heard, and that was the inclusion of a lot of the assumptions that were used in the report, VMT and the assumptions in the base case, and whether or not it includes the various standards and Pavley. So you may not want to address it here today -- or, no, I would appreciate it, Mr. Schremp, if you could -- how much of that is in the report and how much could be added?

MR. SCHREMP: So, again, the base case that was used, what was referred to as the base case, I think, really was the low case from 2007, the low demand case. We used not the exact case in and of itself, we used the growth rates associated with that case. So we really do not have a set of VMT numbers that would be associated with that. At the same time, that case in 2007 did include Pavley 1, and it did include a Zev mandate as part of the assumptions that were associated with it. So you are correct, it did not have Pavley 2 assumptions in there, and it did not talk about Low Carbon Fuel Standard, or any other items that we talked about today, RFS2. But Pavley 1 should have been included in that case. And the prices, fuel price assumptions are fairly consistent with what we are seeing in our current high price, or low price case assumptions.

COMMISSIONER BYRON: Okay, thank you. Our next public comments -- please introduce yourself.

MR. REDEEMER: Commissioner Byron, Vice Chairman Boyd, my name is Michael Redeemer. I am the President of Community Fuels, we are a biodiesel manufacturer, you had to hear from somebody in that industry today, right? We are located at the Port of Stockton and, in 2007, we built -- permitted and built a biodiesel plant, completed it in mid-2008, brought it up into operation late 2008, and we are currently producing biodiesel and selling it throughout Northern California. I wanted to make a couple comments, they are not prepared, but I will submit written comments. I wanted to reinforce the comments that Mr. Schremp made about infrastructures being a limitation. I can speak from personal experience. We sell our fuel through the existing distribution network, we work with fuel distributors. And we have heard many times from them that one of the issues they have is they do not have a tank to store biodiesel at their facility, and they are reluctant to make the investment to put that tank in place until there is a market in their area for biodiesel. So I am hoping that this is one of the areas the AB 118 funds could help support because I think there is a real need, and we are not talking 500,000 gallon tanks, we are talking 10,000 to 20,000 gallon tanks, so it is a pretty simple thing, but there is a real chicken and the egg issue that we are confronted out there day in and day out, so I just wanted to reinforce the comment that there are infrastructure issues that are a limitation. The other comment I will make is the diesel demand forecast for biodiesel 20 years out, at 57 million gallons per year does not inspire a great deal of confidence in our investors. And I do not know if that is something that could be revisited, but at our facility alone, we have the capability of expanding to over 60 million gallons per year, and so to look at a future market that is only 57 million gallons, I think, is a little troubling. And I would point out that, with the new CAFÉ standards kicking in, and the fact that there has been a 5.6 percent growth rate in light duty diesel since 2001, I think you could look at a scenario where existing diesel technology, which has been out there for a long time with the right after treatment, combined with the fueling infrastructure, you could see a diesel alternative scenario for reducing fuel demand. Diesels are 30 percent more efficient than gasoline vehicles. So I would really encourage you to take a look at the impact of these CAFÉ standards and the availability now of light duty diesels that can be sold in California, and see if there is another reality out there that we could at least hypothetically say exists. That is all my comments. I look forward to working with you and your staff and I appreciate the opportunity to address you today.

VICE CHAIR BOYD: Thanks, Michael.

MR. REDEEMER: Any questions?

VICE CHAIR BOYD: A couple comments. The biodiesel demand estimate, yeah, we will take a good look at that. The light-duty diesel and CAFÉ and the potential demand from light duty diesel -- for light duty diesels in California, and thus the fuel demand, is something we have talked about ad nauseum here, and amongst sister agencies just because, while factually you are right in terms of their characteristics and their capabilities, there remains this overriding issue of the unpopularity of light duty diesels heretofore with the California consuming public. So I guess we have looked, we will look, we will continue to look, and maybe the forthcoming generation will have a different view of the potential light duty diesels. And we, too, are just watching the market, our citizens of California responding to the capabilities of this technology, or not. It is a good point, but I do not think our crystal ball is any better than yours at the moment.

COMMISSIONER BYRON: In fact, I would have to add, the staff does a very good job making these forecasts, putting a lot of data forward, but would you really want to base your business plan on a government forecast?

MR. REDEEMER: Well --

COMMISSIONER BYRON: And so your investors should certainly be looking at other factors, and other scenarios, as well, as to what they are going to make their investment decisions on.

MR. REDEEMER: Well, they certainly do, but I do think it is important since it is sort of -- I think the Energy Commission is viewed as a competent expert in this area, that your scenarios are one of those factors, as are the regulations that California adopts. I mean, a lot of the renewable fuels and biodiesel infrastructure is, as we have heard, based on the RFS2 regulations. And so we are all making our decisions based on the world as we see it going into the future. And this is just one datapoint, but I would have to say, 57 million gallons sounds a little light to me, just -- I do not know, but I would be happy to talk to your staff about other scenarios.

COMMISSIONER BYRON: We would welcome that. And Mr. Schremp is up there and hopefully he is not going to defend his forecast, that what he is going to do is talk about why he has not included the scenario you are discussing, then.

MR. REDEEMER: Thank you.

MR. SCHREMP: Well, I was going to fall on the sword over that 57 million until I lost -- it seems like I lost you support about telling Michael to ignore our forecast!

COMMISSIONER BYRON: At least with regard to making business decisions, do not use this forecast.

MR. SCHREMP: Well, actually, Michael, I mean, that is a good point, but I think we do not really have what I would say as bodies of forecasts at this point, we have a reaction to what we think is a minimum RFS2 requirement for biodiesel. I clearly acknowledge that that is eminently doable today, is no supply challenge, but does have some infrastructure issues as you reiterated. We are awaiting some additional pathway information on the Low Carbon Fuel Standard. We believe that, to reduce the carbon intensity of diesel fuel analogous to that of gasoline, you will have to use some lower carbon material. Biodiesels of some sort probably have lower carbon intensities than the base diesel. So we expect to see that probably at least B10, if not even

B20, or beyond, as a necessity to achieve compliance with the Low Carbon Fuel Standard. So biodiesel demand in California, minimum requirement levels, are not going to be driven by RFS2 unless Congress changes those targets appreciably. But we believe there will be significant demand increases from the Low Carbon Fuel Standard, we just have not been able to perform said analysis yet, until those additional pathways and carbon intensities information becomes available. If that happens soon, enough time to modify -- include in our modified final document, we will do so, and then maybe you will have a little bit better information, but it is possible this may be continuing work into next year, as more information becomes available on the biodiesel side. But you are right, yeah, it is a pretty low number.

COMMISSIONER BYRON: Sir, please come forward and identify yourself.

MR. WASON: Yeah, my name is Bill Wason, I am with an organization called Sustainable Bio-Brazil, and I also work with U.S. NGO CO_2 Start. My comments today are directed at how quickly markets can shift if you have certain factors in play. I think one of the most important factors is you have a meeting coming up in Copenhagen and you have an IPCC Report that will come out a year and a half from now. It could change dramatically what the assumptions are of the risks associated with climate change. I think you also have pretty savvy sectors in the private side, looking at these shifts and how quickly they can occur, and what the opportunity is in relation to marketing of low carbon fuels. You have a Low Carbon Fuels Standard that requires a 1 percent reduction per year and a certain RFS standard that assumes biofuel or low carbon fuel introduction on that basis. But the experience in Brazil is really useful to understand. For I do not know how long, they said fully flexed fuel vehicles were no good and did not exist, and the minute that a car company came in with price dip parity, fully flexed vehicle, every car now, minus a few gasoline, you know, super cars, is fully flex fuel and every fuel station has Ethanol, and 80 percent of the sales there on new cars are Ethanol. So I think the same thing could happen in the California market if you defined dynamics and created alliances with the right partners. And I do not think the limitations that you see now, there is a limitation of 5 percent biodiesel, although that Reg is changing to 20 percent, there is already a process, ASTM, in place to do that. In addition, they are not mentioning that renewable diesel technology is already here, and it is going to come into play, and could be blended with biodiesel or sold as a separate component. There is a lot of room for you to look at how you do your avoided deforestation and red planning process in terms of your own state, and how that could lead to both carbon credits on the industry side and, more important, feed stock on the oil side for biodiesel or renewable diesel, or renewable jet fuel, and how that could interplay, as well, with how you deal with indirect land use issues and come up with integrated strategies. We are working and going to present to some of the people at the California Summit an integrated strategy with some of the Governors in Brazil, particularly the Governor of Maranhao, who has a lot of decision-making with some of the other Governors. I think the opportunity is to say, "Where are we going to get large volumes of feedstock on liquid fuels that will deal with a bridge, and how do we work with some of the changes that are occurring in the market?" You have Fiat buying Chrysler -- Fiat is the leading producer of cars in Brazil. Fiat is eager to see partnerships that create the kind of progressive thinking so that they can bring in a whole new generation of turbo diesels that are common in Europe, but not in the market here. Those turbo diesels are a whole lot more exciting if you have a tree planting program and you have an oil seed that is sustainable, and you end up with 100 percent renewable turbo diesel. You are not even depending on diesel. And there, you can introduce the 16 mile per gallon car and it will sell. So that is the kind of thinking that you need to be at to shift beyond the paradigm of what is in your predictions. Your predictions are valid, but are not going to work in a very carbon constrained world that you may be looking at, as soon as 2011 IPCC Report. And I think that is the way to look at the problem, think out the problem, create the partnerships, and you can derail those partnerships real easily if you say, "Oh, indirect land use changed, there is no carbon benefits from this feedstock or that feedstock, or this conversion process, and we do not have any answers and we can't do anything." And I think it is easy to do that because there are other pressures getting you to do that, and I think you are in a perfect position to look outside the box and come up with integrated strategies that work.

COMMISSIONER BYRON: Very good, thank you. I hope you will provide some written comments for this Commission, as well. Thank you.

MR. WASON: Thank you. Anyone else wish to make a public comment here in the audience? If not, we will turn to WebEx.

MR. JANUSCH: Seth Jacobsen, are you on the line?

MR. JACOBSEN: Hello.

MR. JANUSCH: Go ahead.

COMMISSIONER BYRON: Please identify yourself and ask your question, or comment.

MR. JANUSCH: Hi, this is Seth Jacobsen from the

Center for Advanced Studies on Terrorism. First of all, I just want to say hi to Gordon and the rest of the staff, and to thank them for an outstanding analysis and report. I have a quick question and it addresses the notion that all supplying countries are not created equal in terms of crude oil for California. And I wanted to ask whether staff would please add a section to the report that simply describes which countries supply crude oil to California, quantifies and ranks these countries as sources of imports, and describes the past trends and future projections for which countries may supply California with crude oil to meet staff's forecasts.

COMMISSIONER BYRON: So, first of all, do we have that information, Mr. Schremp?

MR. SCHREMP: This is Gordon Schremp. Yes, Commissioner Byron, we have a list of crude oil imports by source country that we can certainly provide in the document, that we revise. Seth, just to be clear, you are also talking about a forward look as to what sources additional crude oil imports may originate from. Is that correct?

MR. JACOBSEN: If possible. We have seen that analysis. If staff is comfortable with the analyses that industry has done, to include that, or reference it. If not, then the trends themselves might be used.

MR. SCHREMP: Well, Seth, I think at minimum we can tap into some of the information that has already been provided as part of the IEPR process. Baker & O'Brien has looked at source countries, or source regions for this incremental crude coming to California. And, you know, staff, we have not done our own analysis in this arena, and Baker and O'Brien does have a great deal of expertise in this area, so staff does not have a problem referencing some information already part of the IEPR process, or even including some of that information in the Appendix in the revised report. So we can do both historical sources of crude oil coming to California by source, as well as some projections by like Baker & O'Brien. We would be happy to do that.

MR. JACOBSEN: Great. Thank you.

MR. SCHREMP: You are welcome.

COMMISSIONER BYRON: Good. Thank you, Mr. Jacobsen, another good comment. Do we have anyone else on WebEx?

MR. JANUSCH: Well, we are going to open the lines up and if anyone has a comment, speak now, or forever hold your peace.

COMMISSIONER BYRON: All right, everyone out on WebEx, you are now off mute. So we are hearing some things that I do not think people expect us to be hearing. Is there anyone out there who would like to ask a question? If so, now is the time. All right, you can re-mute them. All right, staff, well done. I think we are at the close here, then. I would like to thank everyone for being here. Commissioner Boyd, would you like to make some closing comments?

VICE CHAIR BOYD: Thank you, I would. Again, I would say thanks to staff for, as a lot of people said, an extremely thorough and interesting analysis. But I think, as has been evident by some of the comments and testimony today, I think when we get to finally doing what we have to do for the IEPR, which is getting closer all the time, I do think we have to be a little more comprehensive in terms of the fuels. Early on, I got a little concerned that we were heavy on liquid fuels, but not all of them, and no discussion of gas use fuels, including biogas, and electricity, but Felix came up and rescued the day on that point. And so I think we have to make sure that we reach in all directions and do as comprehensive a view as we can take on all the subject areas. Diesel is an area I particularly want to comment on because, rightfully or wrongfully, I have felt for some time now that diesel is a major worldwide problem. Now, at the moment, at the pump, you would not believe it because we are back down to seeing diesel prices here in this country below -- at or below -- regular gasoline again, when for a long time they were above. I think that is an artifact of the recession, the worldwide recession. And I feel that when we get back on our feet and economic demand returns worldwide, and then the forces of industry go back to work, that diesel is going to be a problem. So I am very keen on biodiesel and renewable diesels as something that we need to be thinking about in order to meet the demands of the diesel cycle engine for fuel, it does not have to be petroleum-based, necessarily, either. So I think we will talk more about that internally as we work on this. And one of the last, Mr. Wason, I believe, talked about an integrated strategy, I think we are into that. I do not believe he is here anymore. He came late and left early, so he missed a lot of discussion of the day, and would have picked up more on fully flexed vehicles, which was another one of his subjects. And one of the points I wanted to make, I made it earlier today, is that, you know, for years we have all known the auto companies were going to build a flexible fuel vehicle for practically nothing more than what we would call an "ordinary vehicle." And they do, to get their CAFÉ credits. But what we have lacked is a fueling infrastructure and a lot of talk today about the potential for significant increase in the E85 fuel, but I am very personally skeptical about us being able to supply that fuel because we are a democracy, not a dictatorship, and the fueling infrastructure has been very slow to respond, and I am kind of skeptical as to whether we will see the day. I think we need it. There are vehicles that are capable of using it, but we will have to talk about that more as we finalize our recommendations and report. I did not comment this morning when Mr. Sparano made reference to carbon capture and storage and CO_2 for oil recovery, and I should have.

COMMISSIONER BYRON: And nuclear.

VICE CHAIR BOYD: Well, I was not going to touch nuclear. It is not a transportation fuel, directly. It just makes electricity, and that becomes a transportation…. But the use of CO_2 for enhanced oil recovery has long been done and is well known, but the use of enhanced over cover as carbon capture and sequestration is a little bit different. Heretofore, CO_2 has been used to force oil out of the ground, and with not a lot of thought to whether CO_2 stays there in perpetuity, and so this agency, as you know, is deep into carbon capture and storage research and development, and no pun intended, and still one of the unanswered things is, you know, there are very well known places to put CO_2 such as in saline aquifers or exhausted natural gas reservoirs, that have proven themselves. That is another thing to talk about, oil reservoirs as being a place to permanently store CO_2, so that is going to become a case by case analysis some day in the future, so we just do not leap into CO_2 enhanced over recovery as a carbon offset or a carbon capture and storage. On the other hand, it may be better to inject CO_2 even if some does get out, as long as they can quantify it, then burn valuable natural gas to make steam to stick in the ground. So there may be trade-offs someday, but I do not think we have to venture into that, necessarily, in this particular analysis. But I think we need some discussion internally more about covering the total fuels waterfront and talking a little about the what if scenarios, you know, what if some of these policies do not come to fruition? Or, what if they come to fruition, but the feeling is they cannot be accomplished? What is the alternative strategy that we ought to think about to provide whatever, a form of transportation fuel, to fuel the transportation sector? And this today has been very heavy on conventional petroleum, and I have a concern about, well, what if those projections cannot be realized because you cannot build the infrastructure in question, or you cannot meet the other goals and objectives, climate change, or what have you, that have been played out. And we better be in a position to say what aggressive actions need to be taken in other areas to address that total transportation fuel demand. But I found today very interesting, and it is obvious from the comments of those who were here earlier, or toughed it out for the rest of the day, that this has been a very thorough job in analyzing certain questions. So I appreciate the work that they have done. Enough said.

COMMISSIONER BYRON: Thank you, Commissioner. I was also very impressed with today's workshop. I found it to be very informative and the staff got lots of compliments today from the oil industry, as well as the alternative fuels sources. So, congratulations. I would like to add mine. I thought it was an excellent report and very good presentations. I would also like to give my thanks to the stakeholders for their presentations, and the commenters at the end were also very helpful. I was reminded, looking back at the workshop notice, that we are very interested in your written comments, and the due date for them, I believe, is September 4th. I will let the staff correct me if I have that -- okay, the nods are indicating that is correct. I, too, like Commissioner Boyd, thought for a while this workshop was misnamed -- I thought maybe it was supposed to be "The Liquid Transportation Fuel Forecast and Analysis." I was glad that we did hear from Mr. Oduyemi from Southern California Edison, and that we got into some of the alternative renewable fuels, as well. I am reminded of the loading order on the electric side of the energy equation and Commissioner Boyd was involved in promulgating that a long time ago. We want to use less, first, go after the renewables fuels second, because they really do transform the industry, and renewables by definition are sustainable, instead of depleting all the fossil fuels over the course of time. And I do not mean, as Mr. Sparano indicated earlier, that we are going to run out of oil, but we know that we are depleting fields and constantly looking for new ones. But the loading order is use less, renewables, and then fossil. And I think that applies here, as well. I am reminded, as well from a comment that one of our commenters made towards the end, who has worked in this industry for a long time, he has never seen so much uncertainty as he sees now, and I think that is a concern. To the extent that is true, you know, the staff has done a very good job with the information and the data available to them, and there are many possible futures here that we are trying to consider. The markets will shift, the laws will change, and customers will respond unexpectedly. And that is what I meant earlier by my comment about making business decisions based upon these forecasts. We certainly look towards industry and entrepreneurs that are willing to take ventures into areas that we may not see or understand completely at this point. So I think we have got plenty of good information here today. I look forward to the responses to the comments that we get from the public on this report. Commissioner Boyd, I think we have got a lot of information here to make some good recommendations around transportation or fuels in this year's IEPR. With that, I would like to thank everybody and we are adjourned.

(Whereupon, at 4:18 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, a Certified Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 31st day of August, 2009.

Peter Petty

Peter Petty