STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2009 Integrated	) 09-IEP-1K
Energy Policy Report	)
	)
Transportation Fuel Prices	)
and Energy Demand	)
________________________________	)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, FEBRUARY 10, 2009

9:04 A.M.

Reported by:
Peter Petty
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jeffrey D. Byron, Commissioner

ADVISORS and STAFF PRESENT

Susan Brown, Advisor

Suzanne Korosec

Jim Page

Malachi Weng-Gutierrez

Nick Janusch

Ryan Eggers

Gordon Schremp

Gary Yowell

ALSO PRESENT

David Green
Oak Ridge National Laboratory
Institute for Transportation Studies, UC Davis

Gary Herwick (via teleconference)
Transportation Fuels Consulting, Inc.
California Ethanol Vehicle Coalition

Ron V. Lamberty (via teleconference)
American Coalition for Ethanol

Maurice Hladik (via teleconference)
IOGEN

Sven Thesen
Better Place

Leonard Seitz
Caltrans

Gina Grey (via teleconference)
Western States Petroleum Association

Joe Sparano
Western States Petroleum Association

ALSO PRESENT

Daniel Burke
Caltrans

John Shears
Center for Energy Efficiency and Renewable Technologies

David Modisette (via teleconference)
Public Policy Advocates
California Electric Transportation Coalition

I N D E X

I N D E X

P R O C E E D I N G S

9:04 a.m.

MS. KOROSEC: Good morning, everyone. Thank you for your patience. We just had to wait a few minutes to get our technical stuff all set up here.

I'm Suzanne Korosec. I am the Lead for the Energy Commission's Integrated Energy Policy Report Unit.

Welcome to the staff workshop on the Energy Commission's transportation fuel price and demand forecast. Today's workshop is being held under the direction of two the Energy Commission's Committees, the Transportation Committee and the Integrated Energy Policy Report Committee.

As part of the Integrated Energy Policy Report, or IPER, every two years the Energy Commission conducts assessments and forecasts of all aspects of the transportation energy sector, including supply, demand, prices, infrastructure, production, transportation, delivery and distribution.

These assessments and forecasts are used to develop California's transportation energy policies. And they also feed into related program activities like the Energy Commission's alternative and renewable fuel and vehicle technology program that was established by Assembly Bill 118, as well as the state's efforts under AB-32 to reduce California's greenhouse gas emissions, 40 percent of which come from the transportation sector.

Just a few housekeeping items before I turn it over to the staff to get started. The restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs in the atrium under the white awning.

And if there's an emergency and we need to evacuate the building, please follow the staff to the park that's kitty-corner from the building and wait there for the all-clear signal.

Today's workshop is being broadcast through our WebEx conferencing system. Instructions on how to participate in that system are on the workshop notice that's on our website. And the workshop is also being webcast.

We have a number of presentations today and we will take questions both during and after each presentation. For those who are participating on the webcast you can use the raise-hand feature to ask a question. And our WebEx whiz operator, Nick Janusch, will relay that to the presenter.

After all the presentations are complete we do have time set aside for public comment. When you come up to speak it would be helpful if you could provide a business card to the court reporter so he can make sure that your name is spelled correctly in the transcript.

And depending on how quickly we get through all the presentations, we may need to ask you to limit your comment time to five minutes to make sure that everybody can have enough time to speak.

For parties who are participating by the WebEx who want to speak during the public comment period we'll open the phone lines after we've heard from everybody in the room.

So, Commissioner Byron, is there anything that you would like to say?

COMMISSIONER BYRON: Thank you, Ms. Korosec. I'd like to welcome everyone and thank you for being here this morning.

I chair the Integrated Energy Policy

Report Committee this year, along with Commissioner Boyd, who unfortunately is not able to be here with us today. I understand he's quite ill. However, in his stead is his Advisor, Susan Brown.

And hopefully Diane Schwyzer will join us a little bit later, Commissioner Douglas' -- excuse me, Chairman Douglas' Advisor. And she also serves on the Transportation Committee with Commissioner Boyd.

I am very interested in this subject matter. That's why I'm here today. Unfortunately, I will need to step out a couple of times during the day. And I thank you so very much for being here to help educate this Commissioner and this Commission with your comments and input.

I wanted to add one other thing, and that is in the event any of you are here for tomorrow's business meeting, unfortunately we had to cancel it yesterday, so there will not be a business meeting tomorrow. And that's primarily because we will not be able to have a quorum of Commissioners.

So with that, Ms. Korosec, thank you

very much. I look forward to the workshop.

MS. KOROSEC: Thank you. We have Jim Page from our transportation division come up and get us started.

MR. PAGE: Thank you, Suzanne. Good morning, Commissioner Byron and Advisor Susan Brown, and thank you, guests, for coming. We appreciate your participation today.

Today it is our objective to review the following topics. We want to discuss our overall framework and approach, as well as our demand models, including methods, inputs and assumptions.

We're going to place particular focus today on the transportation fuel price forecasts including crude oil and petroleum fuels, as well as alternative and renewable fuels, which are -- these latter, which are recently added area of analysis to our work in forecasting unit of the fossil fuels office.

So you know where this fits into the overall plan for this spring and summer I'll review where we go from here.

The next step will be after we finalize the inputs to these demand forecasts to continue to work, obviously, on preparing the demand forecasts for a later staff draft. We'll have a second workshop on transportation energy infrastructure and supply issues in probably April.

When we've completed our staff forecast, proposed forecast, we'll hold a third workshop in probably June or maybe July. After which we will finalize the staff report and integrate the results into the IEPR as needed.

And we want to keep this as informal as possible today. We want to keep it open to questions as we go. I don't think that will be disruptive of the presentations.

We do have a lot of ground to cover, and we will, though, try to have lots of breaking points for people to ask questions and make comments.

This chart shows a very broadbrush view of the work we intend to do, the various kinds of data inputs to the demand models are shown along the top, as well as the sources of data, which include transit agencies, the national transit database, the DMV database. Of course, the ubiquitous EIA data, which pervades a lot of these sectors. And then also not shown, the Board of

Equalization data.

These various data feed into the four transportation energy demand models that we show here, plus the offroad analysis. Collectively, these forecasts from these models become our California fuel demand forecast.

On the right in red it shows fuel supply and energy infrastructure, which, as I've stated, will be the subject of our April workshops.

I'd also like to point out, too, contracts that support the CALCARS light-duty vehicle forecasting model. The first is the survey of households and businesses for their stated preferences, consumers towards the vehicle characteristics in making their vehicle purchase decisions.

The second is our vehicle attributes contract which is our means of determining what are vehicle manufacturer offerings of given price and policy cases. Malachi Weng-Gutierrez will discuss that in a moment, but this is a critical path task. In the next few weeks we have to present these cases to our contractor, hence the earliness of this workshop.

I want to emphasize also that these

forecasting cases are works in progress. We obviously think we have good reasons for the prices for forecasting, as well as the cases we're outlining. But your feedback is essential.

There will be at least a ten-day written comment period after this workshop, so we're open to not just written comments, but if you want to call us or email us, we'll be glad to talk with you and entertain the possibilities.

Now, with that brief overview, if there are any questions I will answer them. If not, I'll hand the mike over to Malachi.

MR. WENG-GUTIERREZ: Good morning. My name is Malachi Weng-Gutierrez. I'll be following up Jim's brief overview with a discussion of the models, themselves, a number of the inputs and some of the cases we're going to be considering in this demand forecast.

So, first off, as Jim mentioned, there are four primary models we use. These are the same models we've used in past IEPRs. In 2005, 2007 we used these models to create our demand forecast.

The CALCARS model, as Jim mentioned, really represents the light-duty sector of demand.

It includes vehicles weighted between up to 10,000 pounds. And so I have included in here a medium-duty vehicle category. It has traditionally been referred to as a light-duty vehicle model. But because we do deal with those heavier vehicles I've included medium-duty here. But it doesn't include class 3s and the larger vehicles. It's just those kind of heavy vehicles up to 10,000 pounds.

The CALCARS model, itself, is a discrete choice model. It primarily deals with vehicle ownership and how consumers change their choice of vehicle, given certain economic and market conditions.

As Jim mentioned, we have a number of supporting contracts which we use to estimate the model and to develop the inputs to the model. And I'll discuss that in a couple of slides.

The other models basically the names of the models, themselves, fairly well represent what sectors they discuss. The freight model represents obviously freight movement in California. The transit model emphasizes both urban and intercity transit in California. And then the aviation model is primarily focused on commercial aviation sector.

And of these four models we're going to be primarily updating aviation, the methodology associated with aviation potentially. That's the one model that we're looking at making some changes to.

The other three models will primarily just be updating the inputs, given, you know, the current economic conditions and the recent forecast for different inputs that we use.

And as Jim mentioned, also, we are going to be looking at a much larger slew of fuels than we have in the past. In 2007 we primarily focused on gasoline and diesel forecasts of demand. But this time around we are looking at expanding the number of fuels that we'll be forecasting to these nine.

And they all represent different challenges, certainly, in trying to come up with the appropriate inputs and how we're going to model them and those sorts of things. And I think when we get into the fuel prices, themselves, the nuances of those fuel price forecasts will, if there are questions, those might come up, as well. And we certainly are looking for input into how we should potentially handle some of these alternative fuels that we haven't dealt with in the past.

I'd also like just to mention that we certainly, our office met oftentimes with the emerging fuels and technologies office to gain insight from their knowledge of these areas in the development of some of these forecasts, as well as the input of just the industries, as themselves, the alternative fuel industries and the nuances associated with those industries.

The inputs to the models, the economic and demographic inputs that we use, primarily are composed of these items here: The population forecasts for California, the employment growth rates and personal income.

All of those come from the demand analysis office internal to the Energy Commission. We look to them to produce numbers that will be consistently used to cross all activities in the Energy Commission.

And they primarily get much of this data from the Department of Finance, but then they also have other sources that they include in the development of these numbers, which they disseminate throughout the Energy Commission.

The industrial activities for 23 sectors or NAICS codes, are also used as inputs into the models. We primarily get those, again, from the demand analysis office. The source of those is actually not Department of Finance, but other sources, economy.com, and other sources. So we look to them, the demand analysis office, oftentimes for these long-time series inputs.

The onroad registered vehicles we get from the Department of Motor Vehicle registration database, which we have internal to the Energy Commission. We handle and have a contract to deal with those.

We update that as regularly as we can. We get file -- twice a year. And we try to make sure that the base year that we use for our forecast includes the most up-to-data that we can for all of the different data sources. But primarily the DMV database plays a big role in that. As long as we're comfortable with that DMV population estimate for that base year, then that's what we primarily use.

The other two inputs, fuel prices, which we'll be discussing today. Again, very important.

And we look forward to any input that the participants have regarding these fuel prices and the methodologies we've used to determine them.

The transportation costs we've included. I put down here fares and ticket prices. I know that in the consideration of revising the aviation model we're certainly going to be looking at different types of fares and how they play into the activity in those areas.

And then the other two components that are not listed here as inputs that I wanted to talk about briefly, are the two contract services that Jim had mentioned earlier that support the CALCARS model.

So the first of those is a survey that we have that goes out and asks Californians under certain different conditions what choices would they make. It's a stated preference survey and it gets -- it attempts to gather information about consumers' preferences in today's market.

So we're currently -- that contract is undergoing; it is currently active, we're actually collecting information right now. And we should have all the information by the IEPR, far in advance of the IEPR, far enough in advance so that we can include it into our model.

And that's a key point in making sure that our model is up to date and reflecting the current conditions, what people are feeling in the marketplace, and how they're reacting to the market.

The second contract we have in support of the CALCARS model is the vehicle attributes model. We have a consultant who basically does technology forecasts given certain conditions and certain inputs.

Primarily what we give him are policy cases as well as our price forecast. And under those conditions he looks at the existing fleet of vehicles that exist in California. Looks at what OEMs are going to be introducing in the future as far as given the policy cases that we've provided to him, as well as the different prices we've provided.

And from that he provides us with an estimate of the vehicle attributes, and those are then put into the CALCARS model as part of the choices and options that consumers have for those future vehicles.

In the last IEPR we had six cases that

we evaluated. This time we're expanding the number of cases slightly. And the attempt here is to kind of capture the range of potential demands that we would see under certain policy scenarios.

The last IEPR we chose to have three price forecasts or three sets of prices, a low, a high and then kind of a medium ground, a reference case.

This time around we're actually going with two. We're trying to bound the potential ranges of prices with a low and a high. And then for those two price cases, then -- or those two price ranges, we're setting and looking at a series of policy scenarios.

And before I get into the details of the policy scenarios, I think again it would be valuable to us if we could get input from the participants of the workshop, as well as the Commissioners and Advisors, as to what we would include into these policy scenarios.

Some of these are fairly -- we haven't really necessarily defined them clearly yet. And we're looking for input into these areas to better grasp what we should include and what people are interested in seeing as part of our analysis.

So, for the first set, the greenhouse gas regulations in EISA 2007. The greenhouse gas regulations we've included in the past, have been Pavley 1, as well as the ZEV mandate. We're looking to probably include those as well this time.

EISA 2007 was passed in the latter part of 2007. It includes a CAFE standard which we'll be considering as part of this policy case, set of policy cases. So that'll be primarily our basecase set, or the first two cases that we evaluate.

The second is a Pavley-2 regulation. And we've been -- had a couple staff talking with ARB, getting a sense of what the Pavley-2 regulations will look like.

There are a couple of documents out there that reflect what -- show, basically, what they intend to do. And so we're going to use those as the basis of that second set of cases.

This will be on top of EISA, as well as the ZEV mandate. And so we hope that it'll be slight -- I mean it'll have a distinct result associated with it. But we're trying to get a sense of what the impact is in relation to EISA, as well as the ZEV mandate, the first two sets of cases. So that's that second set of cases.

The third set of cases -- well, the third and the fourth basically deal with incentivizing alternative fuel vehicles in different ways.

The first set here which talks about lowering or incentivizing the alternative fuel prices really is going to be looking at what types of things can we do to the fuel prices of alternative fuels that might promote their use or impact lower demand for gasoline and diesel products.

So, again, when we go through the price forecasts and we're talking about the different alternative fuels, it would be valuable if people can provide us with input as to what types of incentive levels might be reasonable.

Or if there is an existing federal excise credit, would that be reasonable to use throughout the forecast. Things like that would be helpful to us.

For the incentivized alternative fuel vehicle price, what we're trying to get at is how should we look at the differences in the vehicle prices over time. Should we try to incentivize the actual price of the vehicles, themselves, so that people are more apt to adopt them or to purchase them.

And with certain vehicles there's a fairly large incremental cost. And so should the state look at subsidizing those vehicles or having some type of tax credit or some other mechanism to incentivize the purchase of those vehicles. And, again, those would be helpful for us if we can get some input as to what people think might be an effective way of incentivizing the purchase of those vehicles.

And so that's the last set of cases that we have there. And with that I think I'm going to turn it over to Jim, if there are no questions about the cases or -- we do have a question.

MR. SEITZ: Leonard Seitz, Caltrans. I just wanted to ask whether you were giving any consideration to the SB-375, sustainable communities strategies.

MR. WENG-GUTIERREZ: Well, there are a number of other policies out there that we haven't included in our cases. We would have to take a look at how we could integrate them into our models. You know, low carbon fuel standard, SB-375, as you mentioned, there are a number of them out there.

And to the extent that we can get feedback today as to how those specifically might be included or how they might affect some of our inputs we'd be open to considering that.

But we haven't considered how SB-375 would impact prices or the inputs that we have right now in our models.

MR. SEITZ: Just have one other question, then.

MR. WENG-GUTIERREZ: Sure.

MR. SEITZ: Do you have any geographic detail in your analysis, counties or some other level?

MR. WENG-GUTIERREZ: We do have -- well, we've typically just run the models on a statewide basis. We do have information on certain regions. The models have been set up to run for five, or six actually, different regions in California. And they are comprised of a certain number of counties.

So, there's a Sacramento region and it has four or five counties that represent the

Sacramento region. But we typically don't run it in that, at that level. We typically run the statewide number just to get the aggregate values for demand.

But that's something that we're looking at doing in the future. And certainly next IEPR we're going to try to get down to a much lower level of detail. We're trying to get down to the county level to see if we can get some better estimates at a county level and do some other types of demand forecasting, regional demand forecasting.

And then was there a question online?

MR. JANUSCH: -- a question: Where can we find the documents referring to Pavley-2?

COMMISSIONER BYRON: Please come to the podium or repeat the question, if you would, so that we make sure we capture --

MR. WENG-GUTIERREZ: So the question was where can we find the information regarding the Pavley-2 documentation.

There was a response -- I can certainly direct them to the documents that I'm referring to -- there was a response to the denial of California's waiver, and with the response from

ARB that discussed the impact of the Pavley-2 regulations and how it would exceed the EISA 2007 in their rebuttal to the EPA's denial of the California waiver.

So, I'd be happy to direct them to that document.

Are there any other questions? All right, I'll hand it over to Jim.

MR. PAGE: I'd like to just note some of the challenges we -- sort of frame the fuel price forecast this time around.

As you all are well aware the unprecedented volatility in crude oil and fuels markets, at least -- if not unprecedented at least for the last 30 years it has not been surpassed.

The Energy Commission does not have an inhouse world energy model to produce oil price forecasts. We have to basically rely on our judgment or outside sources. The inhouse models and available data support annual average statewide forecasts.

We need, also, as we've noted, to integrate alternative fuel forecasts into the existing inhouse models. And the forecast horizon is to -- long-term horizon is to 2030.

Among our solutions are to assess the use of crude oil price forecasts from EIA, the Energy Information Administration, the International Energy Agency or other organizations.

Our practice had been to use historical data on the U.S. refiner acquisition cost of imported crude oil; the relationship of that to petroleum fuel prices.

For other fuels such as E-85, natural gas, hydrogen and electric rates, we will -- have consulted and will continue to consult with other offices. And, of course, solicit expert advice from outside parties.

Now, I'd like to discuss the crude oil price forecast specifically. It's obviously fundamental to petroleum fuel prices and maybe less directly fundamental to alternative fuel prices, as well.

As I noted, we used the refinery acquisition cost of crude oil, because unlike other commonly reported indices, this represents the average price of crude oil. And this chart simply shows the ranges of prices between various premium oils, such as West Texas intermediate or

Alaskan North Slope and other more commonly used and heavier oils. So the RAC, as we'll begin to refer to it, is an average price for oil.

This graph shows a history of recent, well, 1968, oil prices for the years and corresponding oil demand growth rates. And I think it's a very good demonstration of the kinds of feedbacks that operate on the world oil markets.

For instance, starting in the 60s and 70s, high demand in that period created vulnerability to oil supply constraints, namely the Arab oil embargo, the Iran/Iraq war, after which prices shot up rather severely. And led to, as we might expect, demand destruction and the new nonOPEC supply, particularly Alaska and the North Slope -- excuse me, the North Slope of Alaska and the North Sea.

This led to a price collapse. And the corresponding, the low prices of the 90s. Which culminated really in 1998 in such severe low oil prices that oil production investment fell off sharply. And this led to a narrowing of the excess or surplus oil production capacity worldwide, leaving the world market vulnerable to a increase in demand starting around 2001 to 2003 or '4. And, again, igniting another oil price spike, or at least being a important contributing factor to that.

And then, again, as these prices reached up to over $90 as an average for 2008, we've seen -- and not entirely because of this, as there are other reasons as well -- but a severe demand decline. Or at least a decline in the growth rate.

And this chart shows the same information with just a petroleum consumption in magnitude.

Most of us are familiar with these causes of the oil and fuel price increases from 2003 to the middle of last year. I won't go into them all bur a couple are important, I think.

The rising oil production costs as more difficult-to-extract resources are having to be accessed. As I mentioned, declining excess oil production capacity which reduces the cushion of the world market. There are surges in supply or unexpected production constraints.

And another one I think is important is dollar devaluation, which has been kind of a joker in the deck in terms of trying to price, in the long term, oil.

This, of course, shows some of the opposite trends that led to price declines from the late 2008 into 2009. Again, just to note a couple. There's been a sharp increase in excess oil production capacity, primarily because OPEC now is shutting in production. If they live up to their agreements, it would be 4.2 million barrels a day will be shut in. That's compared to what was probably between 1 and 2 million barrels a day total world excess production capacity at its narrowest.

Also, would want to note the increasing value of the dollar. And this next slide will show more information on that, which I think is a pretty dramatic slide, actually.

The linkage of oil prices to the value of the dollar against other currencies, in this case the Euro. I think it demonstrates a strong correlation; maybe not a total explanation, as there are many factors involved in the price of oil.

But it does raise the question, as we try to price oil in the future, exactly what is this thing we're calling a dollar. Is it changes as much as this graph shows. At this point we don't have any means and don't try or attempt to forecast dollar devaluation in the future.

And at this point I need to note a correction to our report where we mis-attributed our proposed low oil price forecast to the EIA in their 2009 low oil price forecast. This graph shows the corrected version of figure 2 in the report with proper labeling.

And in this chart I'd like to note, first of all, the close, the nearly identical nature of the EIA and IEA reference cases, except for maybe in the near term. I think the fact that both of them project this long-term oil price makes a strong case that we somehow incorporate these cases into our analysis. But how?

Is this, in fact, a reference case or a basecase that we should consider it as being? I personally would have difficulty arguing that. I think what we saw when oil prices did surpass $100 and what happened afterwards as it crashed, I think would argue against that as a permanent, long-term and plausible and sustainable oil price forecast as a most likely case.

I think these oil prices were conceived last summer, or roughly the middle of last year, when oil prices were, in fact, over $100, well over $100.

I'm not aware at this time of really any short-term forecasts in either EIA nor obviously such indicators as the NYMEX, or even in the trade reports, any of the numerous short-term oil price forecasts I've seen that show anything like, you know, sharp increases in oil prices through to the point where we could assume that we'd be hitting and surpassing permanently $100 a barrel comparatively soon.

So, in light of all that I would propose that we use the EIA reference case as a high boundary for our crude oil price forecasts.

Obviously, if we think of the reference case as comparatively high, I think we would have to reject the EIA's high case as, again, is this, in fact, a plausible long-term, sustainable oil price forecast, one that we should use in our planning.

And keep in mind that these are long-term averages. There will be, with given the fluctuation in volatility of prices, normal volatility, around these long-term averages you'd be seeing prices again often well in excess of these numbers, as also below the numbers, too.

Finally, now in spite of current low prices on the other side of side of things, I think there's probably little likelihood that we can expect oil prices to descend to roughly $50 a barrel permanently. Economic growth will eventually rebound. Oil resources are increasingly hard to access.

OPEC, and it's primarily concentrated OPEC countries, and they have their own objectives. In the area recently we've heard of $70, $75 is what they currently think is a fair price for oil.

So, I will proceed then to this chart where we show a price of around, well, in the long term of around $75, $70 to $75 is what we're proposing, CEC Staff is proposing for the low boundary oil price case.

Now, this particular line, as graphed here now, is still in flux, it's in play. I think probably in the short term we should be thinking differently. And I'll go into that in a little more detail in a second.

But this is basically our proposal. That we have a long-term real price forecast of around $75, $70 to $75 at the low end. And a boundary of, well, obviously exceeding $100 around 2014 or '15. And rising to $120 or so in the long term.

Other available forecasts. This shows EIA's annual energy outlook reference cases for 08 and 09, as well as the IEA's 08 and 09 price cases, roughly similar. As well as three other cases, one from Global Insight, another from Strategic Energy Economics Research and Deutschbank.

And what's interesting is these three all have really entirely different trends, but they're roughly in the same neighborhood. They're all well above the $50 low price, too.

So I think this gives me some confidence that as a low end we can use a number like $70, $75 a barrel.

And as I mentioned, I'd like to revisit this, at least the low price forecast. I think the high-price forecast we would leave alone, the blue line. But the red line is, I think, too high in the short term.

This was pretty much a placeholder forecast and I think we need to revise it, as I say, in the short term, to take into account information from, among other sources, the EIA's short-term projections, the NYMEX, which is shown in green, or at least of a recent date. It's probably slightly different now, but not terribly different.

And then there are other oil price forecasts that we see in the trade literature, people's projections for 09 and 10.

The suggestion that I'm proposing today is that we pick a point, a number from in the $40 to $50 range and just shave off this initial bump in the red line, probably intersecting around 2015 or 16 at about $75 a barrel. And then project that long term as the low case.

And that concludes my prepared comments on oil, the low price forecasts. Obviously this is very important. The crude oil price forecast is, as I said, fundamental to the petroleum fuel price forecasts. It's also fundamental, if not so directly at least, but more indirectly to many of the alternative fuel prices.

So, I'm open to questions and I would

love to hear people's responsive comments to what I've suggested.

Hearing none.

Does anyone online have a question?

(Pause.)

MR. PAGE: Okay. Our next -- I'm pleased to note that we have a guest speaker, Dr. David Greene. Dr. Greene holds a PhD in geography and environmental engineering. He is a Corporate Fellow at the Oak Ridge National Laboratory and a Visiting Scholar at the Institute for Transportation Studies at UC Davis.

Dr. Greene has compiled an extensive and diverse body of work in the energy and transportation fields spanning vehicle technology to fuel economy, peak oil to oil security metrics, economic incentives to policy design and assessment.

And he currently is leading a team of UC researchers to assess the impact of fuel prices and different incentive structures on vehicle manufacturing technology development and adoption, as well as consumer behavior to design an effective feebate program.

DR. GREENE: Thank you, Jim.

Commissioner Byron and Advisor Brown, distinguished colleagues and visitors, it's a pleasure to be here.

One of the things I realized 20 years ago was that I couldn't forecast oil prices. And, well, that was the bad news. The good news was I suppose no one else could, either.

So, what I'd like to talk about this morning is some of the fundamentals in this market, and how they make for inherently uncertain and inherently volatile oil prices. That's not to say that we can't understand the range in which that volatility might occur. I think that's a useful thing, as well.

So, clearly it's no surprise if I say that world oil prices will be volatile and highly uncertain for a decade or more, probably more. And I'd like to talk about why.

The fundamental reason, of course, is the presence of the OPEC cartel. Their dominance in proved oil reserves, and even in ultimate oil resources.

But there is what I call a feasible price space in which they operate. And the problem is that feasible price space is very large, as you will see. And so we can, within a given year, see prices that vary by factors of five, six, seven, even eight.

And, of course, as Jim mentioned, there's a great deal of uncertainty at this point about the world economy. But there's also uncertainty about key facts that affect the willingness of energy companies to invest in expanding production of alternatives to petroleum, mostly unconventional oil resources.

First, there is the question of a peak in nonOPEC oil production which is expected very soon, if not any day now. And also the question of global climate change policy, since, of course, the alternatives to petroleum will, without carbon capture and storage, generate anywhere from 10 percent to 100 percent more greenhouse gases.

Without an understanding of what the climate policy will be, this makes it a risky environment in which to invest billions of dollars in expanding production with those kinds of fuels.

I'm very much in agreement with famous MIT economist Morris Adelman who said the real problem the United States faces over oil dates from after 1970. A strong, but he calls it clumsy, monopoly of mostly Middle Eastern exporters operating as OPEC.

Well, you can see in this graph here the change in the world oil market regime that occurred after the first oil price shock in 1973/74. Occasioned at that time by the Arab OPEC oil embargo against countries that assisted Israel in the October war in that year.

We can also see other events here such as the Iran/Iraq war in 79/80 and so on, up to our most recent runup in oil prices and more precipitous decline.

But I think the main point here, first of all, is that OPEC, which had, prior to 1973, been a number of countries in the process of nationalizing their oil resources and gaining control over them, first found its market power in 1973/74. And that led to a completely different and much more volatile oil price regime.

Always, as Jim showed, we see price forecasts that are nice and smooth. They're smooth low or they're smooth high. And when we look at the history it's anything but smooth.

Of course, no oil price forecaster is going to stick his neck out and say we're going to have tripling oil prices next year or something like that. So we tend to generate these kinds of erratic price paths.

But we should realize that that's what's really going to happen in accord with whatever high or low oil price trajectory we're looking at.

Now, I guess people tell me you should never put an equation in a talk, but I just never learned. So I have one equation, okay, and this is it.

It is the equation for the profit maximizing price, that's "p" here, that a monopolist that controls part of the market, not the entire market. So it has a market share here of "s", which might be anywhere from zero to one. What price maximizes their profits.

And you can see it's a function of "c" which is the underlying marginal cost of production of oil in this case. And it's a function of some other parameters, beta here is the price elasticity of world oil. So the more elastic that would be a negative number. The larger that number is the closer the quantity in large brackets will be to zero. And so the closer the profit maximizing price will be to marginal costs, the closer to a competitive market price.

Obviously the smaller that price elasticity is the more market power the cartel has, meaning the higher price it can charge, the higher profits it can get.

Now, "mu" is the response of nonOPEC suppliers, response of the competitive oil suppliers in the world, to a change in supply from the cartel.

So, in this case, if the cartel were, for example, to cut back production by a million barrels a day, how many barrels would the competitive producers bring in at a constant price. Half a million barrels, then this "mu" would be .5.

So this is related directly to the price elasticity of supply in the rest of the world. And the closer it is to minus-one, that is, every barrel the cartel cuts back if the rest of the world can bring a barrel to market, then the weaker their market power is. And, again, the closer that quantity in large brackets is to zero.

Now, the insight that I had 20 years ago was that these elasticities of demand and supply, in the short run, over a period of say a year, are about one-tenth of what they are in the long run.

So that means the profit maximizing price in the short run is enormously higher than the profit maximizing price in the long run. Okay.

And at that time I decided to plot on a graph, as a function of market share, the historical prices for oil against OPEC's market share, and also to plot a curve showing the long-run profit maximizing price as a function of market share, and a curve showing the short-run profit maximizing price as a function of market share.

And this is the updated graph. A lot of these points were missing when I first drew this graph in 1989. But the upper curve, which is shown with bars around it, because, of course, we're not absolutely certain what these elasticities are. And that's really just a notional indication of uncertainty about where that curve actually is.

The short run curve runs from about $55, $60 a barrel up to 100 or more as the OPEC market share increases towards 50 percent of the market. They now are about 40-some percent. The long-run curve is obviously much lower.

And what that means is that OPEC can obtain a very high price for oil in the short run. But they can't sustain that price in the long run. The only weapon they have is to cut back production to keep the price high. And if you cut back production you lose marker share.

And what we learned from the previous equation is if you lose market share you lose market power. So that's, in effect, a downward spiral, as the rest of the world goes out and drills for more oil, explorers develop more oil, develop substitutes, increases the efficiency of the oil-using equipment and so on.

What we see in this graph from 1965 prior to OPEC exercising its first exercise of market power, we see the price of oil in the world is actually below OPEC's theoretical long-run profit maximizing price.

But then in 1974 it jumps above that, stays there for awhile until the Iran/Iraq war takes those two countries' production essentially off the market. And it jumps up into a range very close to the short-run, this is one-year short-run, profit maximizing price.

At that point in 1979 Saudi Arabia was producing more than 9 million barrels a day of oil. Now, they were not the only OPEC country to cut back production, but they bore most of the load in cutting back production.

And so OPEC cut back production, as you can see, year after year in an explicit policy to defend the high price of oil.

By the time 1985 came around, Saudi Arabia's production was down to just a little more than 3 million barrels a day. From 9 to 3. Obviously they could see at that point where this was going. And that eventually they would have nothing left to defend the higher price with.

Several countries abandoned ship first, and then the Saudis did. And, of course, that led to the oil price crash in 1986.

But since they have three-quarters or more of the proved oil reserves in the world, conventional oil, and more than half of the ultimate resources, as estimated by the U.S. Geological Survey, as world oil demand recovered, they gradually increased market share. Until, as Jim pointed out, just after 2000 we saw prices begin to rise again. And ultimately peak in 2008.

And this is, again, the refiner acquisition costs, so we know the price during the year were $130, $140 a barrel. But this is the average price over the entire year paid for oil, and that's much closer to $90, $95 a barrel.

And with the collapse of the world economies, of course we are now here a much lower oil prices.

But the point is at any given time we can be anywhere in that space. It's sustainable by the fundamental economics. And whether we stay for a long time towards the long-run curve, or whether we move towards the short-run curve is not really predictable, because it depends on world events that OPEC can capitalize on. It depends on the fundamentals that Jim described in his previous talk about inventories, about production capacity and so on.

Something that's frequently not mentioned in discussing oil prices is the fact that up until 1970 the largest oil producer in the world was the United States of America. And our oil production peaked in 1970, as shown on this graph. And despite really dramatic improvements in technology of oil exploration and development, despite higher oil prices, despite big new finds in Alaska, our oil production never regained that peak level of 1970.

There really is such a thing as oil peaking. It's now been observed in other regions of the world. And I think there's serious concern about oil peaking or plateau, as you'll see in a moment, outside of OPEC, and what that means for oil prices.

Because this affects that new parameter that I talked about. If the rest of the world is unable to increase production this will magnify the market power of the cartel.

I don't like to use words like alarming, but I think it's fair to say the rate of oil use of the world is alarming. This bar shows the U.S. Geological Survey's median estimate of ultimately recoverable resources of conventional oil. So that's not tar sands, it's not oil shale, it's not coal-to-liquids or anything like that, it is conventional oil.

And they estimate about 3 trillion barrels. That has a huge error bar around it of about plus/minus 1 trillion barrels of oil, conventional oil.

But what I want to point out is that in 1995 cumulative production over the history of the world was 710 billion barrels. By 2005, just ten years later, it was 979. So more than a fourth of all the oil ever consumed was consumed in that ten-year period.

Now the National Petroleum Council, they would probably revise this downward a little bit at this point. Expected 1.1 trillion barrels of oil production over the next 25 years. So that's from 2005 to 2030.

That would clearly take us well beyond the estimated halfway point. In fact, would take us to the halfway point of oil production for even the most optimistic USGS estimate, by 2030.

The point of oil peaking really is not that the world will go back to the stone age or something once the peak of oil is reached. The point is that you cannot keep increasing the rate of production of a finite resource like oil indefinitely when your consumption is so large relative to the quantity that exists. And that's where we are now.

That's not to say disaster is coming. There are plenty of sources of energy in the world. But it is to say that a major transition is coming.

This is the estimate from the International Energy Agency of nonOPEC oil production done three years ago. They suggest a plateau right around now, 2009, 2010.

This is Exxon Mobil's most recent projection. Just to show you it's not just whackos, but the most profitable company in the United States also foreseeing this.

This is in light of the high oil prices they saw. Now, of course, they didn't think oil prices would stay above $100 indefinitely either. But they see, in effect, a plateau of nonOPEC production.

I like this because the graph they showed in the previous edition was kind of dark and gloomy and this one is much brighter and pastel colored and optimistic.

Anyway, this was their projection of three years ago, at somewhat lower oil prices. They actually saw a peak in nonOPEC crude oil production.

But the point really is that new parameter, the ability of the rest of the world to supply oil becomes tougher and tougher and tougher as this happens. And essentially gives enormous market power.

Here they show OPEC filling in the gap. They euphemistically call this the call on OPEC. OPEC, please produce this much oil. Of course, yesterday OPEC canceled a bunch of projects that they had previously announced for expanding oil production.

So, the result of all this is highly uncertain future oil prices. Uncertain because of the market fundamentals and uncertain because of the difficulty for firms to invest in expanding unconventional production when they don't know when the oil peak will occur, and they don't know what the rules are going to be for greenhouse gas emissions. But they can guess at this point, I think.

So, we also don't know, as Jim pointed out, when the world economies will recover and the oil demand will begin growing again. That affects the equation, as well.

We don't know how much OPEC will expand production, how much they're willing to produce. We have several studies of these. And one of the things that makes it so uncertain is that the total revenues to OPEC, over a long period of time, are not particularly sensitive to the price path they take.

Several studies have shown that repeated price shocks gives them the most profit, but it's not that much more than a relatively high price sustained over a long period of time. So, exactly what they're going to do is therefore very difficult to predict.

And I pointed out the difficulty that energy companies face in deciding what investments to make. I will say that they did not assume -- prices for investments in the vicinity of $100 a barrel back when the price was that high. They were more around $50 a barrel, I would say, or even lower.

And just a final point, I think, when we're considering what to assume about oil prices we should take into consideration the economic costs of those volatile prices on our economy. Because whether the price is high and stays high, or whether it's volatile, we are still going to bear large economic costs.

These are my estimates of the economic

costs. And you can see that for 2008 those costs are exceeding half a trillion dollars. I don't think this is the sole cause of the economic crisis we're suffering today, but certainly a contributing factor.

And as we go forward we can essentially expect more of the same unless we seriously address this problem and deal with it comprehensively.

So, thank you for your attention. If there are questions I'll be happy to answer them, or try to, anyway.

COMMISSIONER BYRON: Dr. Greene, if I may.

DR. GREENE: Yes.

COMMISSIONER BYRON: This is all very good stuff. I'm not an economist; I have never seen the curve that you showed back on about figure 5 or so. And I'm just wondering, because there's a few additional pieces of information that have a tremendous factor in all of this, I would imagine, one being how much oil or reserves the cartel possesses. So when their market share dropped off for long periods of time clearly they were retaining more reserves.

And I've also, of course, read or understood that national oil companies tend to over-estimate their reserves.

How important is the reserve and how much of a handle do we have on that? What kind of effect would it have on their ability to control prices going forward?

DR. GREENE: Right. Very good question. I think that reserves, per se, are not the issue. Reserves are essentially an inventory that these countries maintain as a plan for their future production.

So the question is how much oil do they actually have, what are their resources. Because proved reserves, at least in the United States, you have to have drilled down into the oil and mapped out the extent of the oil that's there. And be sure that it can be recovered at reasonable prices.

The problem is those same rules don't apply to OPEC. And so lots of times their announcements of reserves are more for their own internal bargaining purposes as to what a given country's allocation quota will be. So reserves are not the point.

The point is how much oil do they actually have. There the best number I think is the U.S. Geological Survey's ultimately recoverable resource estimates.

Now, the U.S. Geological Survey thinks that OPEC has a lot of oil. There are others who think that OPEC does not have that oil. It's very difficult to resolve because they won't tell us.

So, not being a petroleum geologist, I'm not able to resolve that argument for us. But it certainly does matter a lot. If OPEC does not have the oil that they say they have, or that the U.S. Geological Survey says they have, then we're not just talking about a question of nonOPEC oil peaking, we're talking about global oil peaking.

So that's a very important question. Supposedly the National Petroleum Council was going to answer that for the Secretary of Energy. They never really did. They did title their report, Hard Truths, which I guess convey some sense of where they think the situation is. But they never really answered that question as to do they really know.

I don't know if that is responsive to your question or --

COMMISSIONER BYRON: It's certainly responsive, but it doesn't tell me what's in the future, or what the crystal ball says, though, does it?

DR. GREENE: Yeah, I'm afraid that's where we are.

COMMISSIONER BYRON: Susan.

MS. BROWN: Yeah. Dr. Greene, I'm curious to know if you're able to track industry investments in unconventional oil. There's got to be some investment. I think you mentioned that it was largely tied to, you know, one's perception of what's in the ground. And certainly the financial situation today isn't going to help finance these alleged, you know, risky investments.

DR. GREENE: Yes, this is -- these are tracked.

MS. BROWN: Do you have any thoughts on that, or, you know, have you seen any data or are there trends there --

DR. GREENE: I don't --

MS. BROWN: -- that you can --

DR. GREENE: I don't have hard numbers to give you off the top of my head. But they do exist. And we do know, for example, that consideration of investment in oil shale in the U.S., for example, we have perhaps a trillion barrels of recoverable oil from oil shale. That's a tremendous amount.

That's really at research stage, experimental stage, even now. So the companies are not making -- and I think now they're glad they didn't, make any massive investments in producing oil shale.

In Canada, of course, they've been ramping up the tar sands production. And my understanding is that some of the more recent investments at today's oil prices are not economical. But that most of the previous ones were economical, even at $20, $30 a barrel of oil.

Most of the interest is in producing more conventional oil. And being able to produce that at prices -- I think, obviously the industry won't tell you what their hurdle prices are, but I think they're more like in the range of $30 to $50 a barrel.

MS. BROWN: What about gas shale? We're hearing a lot from natural gas pipeline companies that, you know, natural gas shale is the new boom. Does that give any indication of what could happen with the oil shale, or is it just completely separate market?

DR. GREENE: I think it is a separate market and I'm not an expert in that, so I'll decline to answer the question on the grounds I don't really know.

COMMISSIONER BYRON: Are there any other questions for Dr. Greene?

MR. JANUSCH: We have Gina Grey on the phone. Gina, go ahead.

MS. GREY: All right, thank you very much. This is Gina Grey with WSPA. And interested in your remarks relative to the domestic oil production.

And perhaps I was sort of left with sort of an impression that you didn't mean to convey, but in your remarks it seemed to me that you're saying that because of the -- despite the increases in oil production rates and all the new technology, et cetera, et cetera, that, in fact, your feeling is that the domestic oil producers have sort of achieved that peak oil realm.

But there's no mention in your remarks of domestic oil policy and how that may have significantly constrained the ability of the industry to go out and do exploration first to identify, you know, finds; and then secondly to actually produce.

So, interested in your comments on the policy side.

DR. GREENE: Right. I think I did mean to convey that the U.S., as an oil-producing region, which actually there's more than one region, but collectively, has seen its oil peak.

However, that doesn't mean it's irrelevant to our national energy policy how much oil we produce. Whether the decline is very fast or whether the decline is slowed or even stopped for awhile that can make a huge difference.

And, in fact, my analyses, which are -- it's another talk all together on achieving oil independence, which is not using no oil or importing no oil, it's getting the problem to a manageable size.

But if you want to do that it's clear, from my -- to me, anyway, that you must have a comprehensive policy. And that comprehensive policy has to include not just improving the fuel economy of motor vehicles, but getting home heating oil out of -- getting distillate fuel out of home heating business, and increasing the supply of domestically produced oil.

There are environmental issues, to be sure. And I think those have to be taken very seriously. But I also think that a key element of achieving energy independence for the United States is significantly increasing our domestic production of conventional oil and other substitutes.

MS. GREY: Thank you.

DR. GREENE: Okay.

MS. BROWN: I have one last question. It's more of a curiosity. At one point the United States had roughly 25 percent of the world oil consumption, I believe, and 2 percent of the reserves? Those are rough numbers. Is it about the same? Have we changed? Demand's got to be somewhat slacked off, but I just wondered what your thoughts were --

DR. GREENE: The situation is basically the same. The only thing that's changed really significantly in our position over the past 25 years or so is the amount of oil that we import has grown considerably because of our peaking of oil production.

COMMISSIONER BYRON: Mr. Sparano.

MR. SPARANO: Dr. Greene, thank you, that was very interesting material. I wanted to clarify a few things. This is Joe Sparano with Western States Petroleum Association.

I think Gina's question on policy is instructive, and your followup question, Susan, was, as well. The U.S., according to the same USGS that you cited a number of times, has reserves on- and offshore in just federal lands of something in the order of 116 billion barrels.

And when you look at what we have in terms of proved reserves today, 21 or 22 billion barrels to the U.S., that's a pretty significant amount. Five or six times as much. Public policy does not allow industry to get at much of that.

And so when you add to that the unconventional sources that you cited, which include shale, a trillion more barrels, depending on who's looking at it and what price forecast they're using. And perhaps more impressive to me, as an industry person, is the abundant amount of pretty well proved reserves in the form of oil sands in Canada, 178 or so, 175 billion barrels. That's a lot of years of supply provided it can be brought to market in an environmentally sensitive way. And the issues that are related to climate change are addressed by the Canadians. And they've got billions of dollars invested in trying to figure out how to do that.

But when you consider all of those materials, our production went from 10 million barrels a day in the U.S,. in the early 80s when the Alaskan North Slope was producing at its peak levels, down to under 5 million barrels a day last year, caused in part by the hurricanes. But also because of the public policy prohibitions to accessing on- and offshore oil.

I think you can get a sense that there is oil out there. It can be brought to market. First, we have to have the ability to identify it, explore for it, get drilling permitted, produce it and then bring it to market.

If you believe that that can be accomplished, then I think to get back to what we've been talking about, you have one price forecast. If you believe that that's not do-able then you have a wholly different price forecast, which potentially goes off the charts.

If OPEC is unable to produce at a higher level, for whatever reason, and if the United States and Canada and Mexico, which collectively possess a tremendous amount of technically recoverable, but not yet accessed and produced, material, then you're looking at a real significant issue with respect to pricing.

And I just wanted to make those comments in addition to augment what Dr. Greene brought to us.

So, again, thank you for your comments and your data that you brought.

DR. GREENE: You're welcome. Did you want an answer? I don't think you --

COMMISSIONER BYRON: Go right ahead.

DR. GREENE: -- need an answer, do you?

COMMISSIONER BYRON: Go right ahead if you'd like to respond.

MR. SPARANO: Yes, please.

DR. GREENE: Well, I think that, as I said, we need -- if we're going to solve our oil dependence problem we need a comprehensive policy. And that comprehensive policy will have to include, if it's going to be successful, will have to include producing more oil in the United States, producing more substitutes for oil in the

United States, as well.

And I think it is possible to address both the oil dependence problem and the climate change problem at the same time. But it's going to require a truly comprehensive approach, and it's going to require some of everything. It's not, drill, baby, drill, or conserve, baby, conserve. It's everything. And we have to put it all together at the same time.

So, we also need a lot of technological progress, as well. So we need all of the above. I think it's do-able. And so I guess I basically agree with what you're saying.

MR. SPARANO: Thank you. You asked a question, Susan, about the amount of investment in unconventionals, and the API has produced some statistics over the last seven years from independent third parties.

And something on the order of $188 billion has been spend on a combination of frontier hydrocarbon, which are the unconventional oils, oil sands, oil shale, activity mainly in North America, as well as end uses for fuels, as well as biofuels of all sorts, solar and wind.

And the petroleum industry has invested

about $120 of that $188 billion. So there's very aggressive activity.

And I really appreciate your comments, Dr. Greene, about the mix of things we need to have to come together in terms of policy to address this issue. And when we talk about that in an open forum usually we'll cite conservation, using less of whatever we use.

Energy efficiency in particular, that's an industry, manufacturing industry issue where people and businesses need to use the fuel that they use more efficiently.

Our industry, as I just mentioned, is heavily invested in both unconventional and renewable and alternative fuels. And those all need to be considered and brought to market.

And our message is don't rule anything out. And, Commissioner Byron, we've talked About that a lot of different times over the last few years. Rather than trying to push material off the table in terms of its future use, embrace all different forms of energy as long as they're scientifically sound, technically feasible, clean and cost effective.

And if you hit all four of those marks

we probably have a pretty good energy supply situation ahead of us.

And then finally, accessing the material that we know is out there, that from a public policy standpoint there have been prohibitions of one sort or another.

And so I think, looking at this IEPR as we have, this is my third one, I guess, since 2003. So the fourth total. The issue has always been what, if any, materials will we push or try to push out of the picture, and how many of the newer materials that certainly will be part of the future energy supply portfolio, how many of those are ready for prime time. And if they're not, what has to be done in terms of incentivizing them to get them on the table.

So, I appreciate what you all are doing here today.

COMMISSIONER BYRON: Thank you, Dr. Greene.

DR. GREENE: You're welcome.

MR. PAGE: Now we'll have Ryan Eggers of staff present the petroleum transportation fuel price forecasts.

MR. EGGERS: Hello. My name is Ryan

Eggers. I will be presenting information regarding the Energy Commission's petroleum fuel price forecast.

To create California-specific regular-grade gasoline, or RFG, and diesel fuel for gas, Energy Commission Staff has elected to use a commodity-based approach to building that forecast.

This approach assumes that the base commodity, in this case the refiner acquisition of cost of crude oil, is the primary basis for variation for these fuel prices into the future. The basis of this assumption will be explained in following slides.

Using this price index as the basis for this forecast, the next step of the calculation process is to establish refiner and dealer margins. The refiner margin or the RAC-to-price margin brings the refiner acquisition cost to a wholesale market price.

The next margin, or the dealer margin, is the RAC-to-retail margin, which elevates the wholesale price to a pretax retail price. After getting to that pretax retail price we then add the final step in the calculation process involves adding the appropriate tax structure to the fuel in question, either gas or diesel.

In the case of gas these taxes total 37.8 cents per gallon, and a generic 8-cents state sales tax was used to bring the final price to its market pump price.

For diesel, excise taxes total 43.8 cents per gallon, with 18 cents that tax being added after the 8-cents sales tax.

It should be also noted that these forecasts, starting at 2010, included in ethanol 10 adder costs, which was to estimate increased costs that are RFG fuel formulations will incur due to the E-10 change.

In the high RFG case this adder starts at 5 cents in 2010 to 2011. And in 2012 raises to 10 cents. In the low case it starts at 2.5 cents in 2010 to 2011. Then in 2012 raises to 5 cents in later years.

Key assumptions to this forecasting method are refiner and dealer margins are both held constant and inflation-adjusted or real terms. All tax structures are also held constant in inflation-adjusted terms.

And that these forecasts only model the

current and planned fuel formulations for California. And that these fuel formulations stay constant into 2030.

The reason for choosing this forecasting method is based on market behavior of the past six years. The reason for using only the last six years of information is due to the subtraction of MTBE from RFG fuel formulations. Thus these years best represent market behavior under the current fuel formulations.

Shown here are RFG and diesel RAC-to-Rack margins from 2003 to 2008. While variation in these margins do occur, there does not seem to be a trend in that variation, whether increasing or decreasing.

It should also be known that diesel margins have come to the point where they seem to be higher than RFG margins for the RAC-to-Rack price margin.

Instead, as seen on this graph, when adjusting for inflation, a stronger correlation seems to occur from the refiner acquisition costs shown in the blue line right here. And the pretax retail price of both diesel in the green line, and gas, which is the red line shown on this graph.

RAC-to-Rack margins and RAC-to-retail margins shown as dotted lines, again, green for diesel, red for gas, both seem to remain relatively constant during this timeframe. Thus supporting our assumptions that they will stay constant in real terms into the future.

After establishing that refiner and dealer margins are constant, Energy Commission Staff estimated these margins using EIA and OPES information.

For the high forecast for both RFG and diesel, 2006 to 2008 averages were used. These averages, as seen here, were 67.2 cents for gas, and 76.7 cents for diesel for the crude or Rack- RAC-to-Rack retail margin. Dealer margins were for gas, Rack-to-retail 15.5, and for diesel 18.1.

Also shown here are the E-10 adders, both 10 and 5 cents. CEC, or the Energy Commission lows for gas for RAC-to-Rack margins for gas that was 66.7 cents. And for diesel, 66.9 cents. For Rack-to-retail margins for gas it was 14.9; and for diesel, Rack-to-retail margin, the margin used was 16.9 cents. Again, the adder shown in the last two columns.

These margins were then added to the

refiner acquisition cost forecast estimates, both high and low, producing the following results. Both forecasts are under $3 in 2009.

And in the high case, rises to just under $5 for gas and diesel in 2030. In the low case estimate, again it starts below $3, and then rises, and then levels off to just under 3.50 in 2030.

Now, both of these were presented in real or inflation-adjusted values. This is not necessarily the price you would see in the pump. Instead, in nominal terms, these prices become much higher.

When using moodyseconomy.com California inflation-adjusted forecasts, these prices rise much more quickly, while again, both started just around $3 a gallon in 2009. In the high case it rises to just under $7, which is approximately what we estimate you would see at the pump at 2030. In the low case, much less a rise. But, again, it's much higher than in the inflation-adjusted terms.

COMMISSIONER BYRON: Mr. Eggers, if I may interrupt for just a moment?

MR. EGGERS: Yes.

COMMISSIONER BYRON: What do you attribute the relative peaking that's taking place on the low RFG case around 2013, 2014, and then it descends. What's causing that early peaking?

MR. EGGERS: Nothing specifically. What happened is when we generated the low forecast we used the previous EIA's reference in low forecasting. We estimated the percentage differences between those two forecasts. And then we applied it to this year's 2009 AEO forecast.

The reason we did it is because they have not published a low forecast as of yet. The one that Jim presented previously was basically our estimate of what was seen on a graphical representation that the EIA presented in their December presentation.

MR. PAGE: This is where I was discussing the short-term oil price forecast. We were thinking of, you know, filing down the short term on the low case. That bump is attributable to the crude oil price forecast.

COMMISSIONER BYRON: Okay, thank you.

MR. PAGE: And I guess I should note, it'll show up in other places, too.

MR. EGGERS: After seeing all this, one

might wonder why not just use the EIA's produced forecasts in order to estimate California prices.

The first reason we did not do this is because the EIA only produces a U.S. average motor gasoline price forecast. The second reason is even while using the historic data to determine the average difference between that price and the actual California price, EIA forecasts tend to traditionally be less than our analysis would indicate they should.

The next two price forecasts that will be discussed are derived directly from the diesel forecast result. They are the railroad diesel and jet fuel price forecasts.

In the case of railroad diesel the diesel Rack forecast, which was the RAC-to-Rack margin of light and crude oil, in the case of diesel, was used; and then a 6.9 cents per gallon excise tax, which includes both state and federal excise tax, was added to the diesel Rack price. Then an 8 cents California sales tax was added to bring it to its final price forecast.

In the case of jet fuel, again our Energy Commission diesel Rack price forecast was used. A 6. cents per gallon excise tax, both state and federal, was then added, along with a distribution adder accounting for the transportation of this fuel to various sites.

This distribution adder is roughly one-half of the diesel Rack-to-retail margin. Once all that is added, again an 8 cents California sales tax was then added.

Shown here in inflation-adjusted terms, are our railroad diesel and jet fuel price forecasts. Again, we have that spike on the low mainly because these patterns mimic our crude oil forecasts just with margins added to them on a per-gallon basis.

MS. BROWN: Sorry, Ryan, are those -- those are constant dollars?

MR. EGGERS: Yes, these are 2008 sets. So they're real dollars.

MS. BROWN: Real dollars, not inflation.

MR. EGGERS: Inflation-adjusted, so they don't -- they're not nominal. Or they don't have inflation added to them.

Any questions?

MS. BROWN: I had a couple, --

MR. EGGERS: Okay.

MS. BROWN: -- if I might interject.

First, what's the primary reason for the difference in the diesel margins? Is it that we're diesel supply short?

MR. EGGERS: It's just the different fuel formulation type. I am not aware of any like, any other underlying differences. Perhaps, Jim, are you aware of --

MR. PAGE: Yeah, I think what we've seen recently, and this is one of the questions I would hope that maybe we could get some comment on, it seems like the diesel price, by inference the margin, particularly the refining margin, has been much larger recently. There's disparity.

Now, I was surprised when we looked at the numbers how close, like in 2007, these margins really were between gasoline and diesel. Because I just assumed it was much larger.

We saw it again, we saw the increases in 2008, but that appears to be more because the margin for gasoline fell, not that the one for diesel increased.

I was sort of assuming, I guess, that world demand for diesel has been so strong recently, you know, the developing country demand in particular, as opposed to maybe a less demand growth for gasoline. But it's just a little hard to tease it out in the numbers.

The difference we actually settled for, I think Ryan found, was 10 or 11 cents in the high case, which concentrates on the most recent years.

So that was a little surprising, but that would be the explanation.

MS. BROWN: I had another question, and I guess more of a curiosity. When you compare California reformulated gasoline to the U.S. average, what's the price spread today? Do we know?

MR. EGGERS: Unfortunately, yeah, I don't have that number right off the top of my head. I think it's close to around 20 or 30 cents, but I wouldn't --

MR. PAGE: It varies some, but, yeah, that's usually what we figure.

MS. BROWN: Sure. Thank you.

MR. EGGERS: Gordon.

MR. SCHREMP: Gordon Schremp, Energy Commission, senior staff. And to your question, Susan, Ryan's right, Jim, that the price over the last several years has -- the retail price in California versus the average U.S. price, which, by the way, also includes the California number, is around 25, 20 to 28 cents a gallon.

Most of the difference, a large fraction of the difference, will be due to the total tax burden at the retail. California usually has some of the highest tax, total tax in the final price. Primarily because we have the application of sales tax last.

So that is why you will see -- so California's prices should be higher because of that average tax differences, the state being at the very top level for retail prices, that's correct. And you should have higher prices if, in fact, we are a net importer of gasoline and gasoline components. You would need to attract that gasoline blend stock from other locations, both domestically and internationally.

So our prices being higher do have, there's a rational explanation for seeing that historically.

MS. BROWN: Well, I've been around long enough to know that 12 cents used to be a large number, and now it's double that it sounds like.

MR. SCHREMP: Yes.

MS. BROWN: Thank you.

COMMISSIONER BYRON: Well, and does it stay normally about a fixed percentage difference? Or does it fluctuate?

MR. SCHREMP: It fluctuates due to other near-term factors that are occurring in other parts of the United States geopolitically, or in California.

Once again, keeping in mind that what goes on in the NYMEX, the futures market, is a linkage to our wholesale prices, spot prices in California, and wholesale prices.

So, for example, a hurricane not directly impacting California can raise the futures prices which have a direct, almost immediate impact on wholesale prices in California that translate to retail prices.

So that's an example where you can see geopolitical or outside events raising our prices. Also we have local factors that come into play because those wholesale prices in the NYMEX linkage has to do with the premium being paid currently in the marketplace in California.

That premium is usually greater than the futures price. The quotations are probably 10, 15, 20, 25 cents a gallon premium. But we do see times when our premium is at a discount to the NYMEX. That's unusual.

So, Commissioner Byron, we do see times when California will be, I think, lower in terms of a near-term wholesale price. That's because of the local conditions in the marketplace here. At other times we'll see premiums in excess of 45, 50 cents to the futures price because we have a local supply problem.

So, we do, over the period of a year, see these fluctuations in wholesale and then retail prices due to either local, near-term supply difficulties, or geopolitical events, or natural disasters outside of California.

COMMISSIONER BYRON: Thank you. I knew it wasn't constant, but I didn't realize how complicated the answer might be.

Please identify yourself.

MR. BURKE: Daniel Burke from Caltrans. My question is do you take any -- I'm looking at your assumptions here. And is there any reason why you do not take consumptions trends into account when forecasting any of the fuel prices?

MR. EGGERS: Jim.

MR. PAGE: Yeah. Well, we don't have

really any system for iterative supply price versus demand. We have no mechanism for doing that.

Obviously the basis of all this is the crude oil price forecast. That is a judgment call. We have to assume that it takes into account expectations of demand and so forth. So that's sort of built into that time series. The numbers we add onto it, the margins, are simply reviews of historical trends.

Now, you know, it could be that, well, in that case you'd have to assume, to vary that you'd have to assume that there are going to be changes in the economics of refining. And certainly that would happen if you had fuel specification changes and things like that, as we showed with the predicted model E-10 changes.

But that would not necessarily be affected by demand, that component. Nor the dealer margins which tend to be constant. Or taxation, if we assume it's constant.

So, in the step-by-step process of building it, really the only place that demand gets incorporated is in the judgment call of where crude oil prices are going. So it's sort of built in there, but not explicitly, you know, modeled as if it was a high-demand or a low-demand situation.

MS. BROWN: Jim, can you speak up a little bit, or get closer to a mike? I'm sorry, we're having trouble.

MR. PAGE: Well, just the notion that demand -- that the crude oil price forecast, it has assumptions about long-term demand built into it as a judgment call. There's no explicit give or take based on different scenarios of demand in that crude oil price forecast.

And the other components, it's simply not a factor.

MR. BURKE: Okay. And secondly, I'm unfamiliar with the Pavley rules, what are the Pavley rules?

MR. WENG-GUTIERREZ: I think that question was --

MR. PAGE: Malachi, could you --

MR. WENG-GUTIERREZ: Yeah, --

MS. BROWN: I can answer that. The Air Board adopted greenhouse gas limits for motor vehicles. First phase is subject to a federal waiver request, which we expect to be approved by the Obama Administration.

And I believe they have built into the climate action plan a second set of regulations that would further limit GHGs from motor vehicles. So it's an Air Board regulation, assumes, which is a de facto surrogate for efficiency.

So we factor that into our demand projection.

MR. BURKE: Okay.

MS. BROWN: Does that help?

MR. BURKE: Yeah, thank you.

MR. EGGERS: Is there anyone on the phone who has a question now?

(Pause.)

MR. EGGERS: Okay, thank you.

MR. PAGE: Thank you, Ryan. Next we'll have Malachi return and discuss renewable fuels price forecasts.

MR. WENG-GUTIERREZ: Thanks, Ryan. What I'm going to do is just go over the E-85 price forecasts. We discussed with the emerging fuels and technologies office a couple of times how we should approach E-85 pricing. There certainly is a couple of different methods you could use. And we decided to present both that we felt could be used.

So, to capture the range of potential prices that we're going to see, we could see in the future, we're basically pegging the price to gasoline, our high and low prices that we forecasted, on a volumetric and a energy-equivalent basis.

So the upper bound of the pricing is going to be equal to the gasoline price forecast on a volumetric basis. And the lower bound would be equivalent on an energy-equivalent basis.

And as this last bullet notes, we haven't yet determined which of the values that we will be using as the range of values in our forecast. And we would value any input from the participants or Commissioners regarding what might be a useful range to use. In addition, in our charts we've shown central tendency value which could also be used, as well.

So, before I got into the actual forecast I wanted to describe basically or explain a little bit more about volumetric equivalence and energy equivalence, and then the concept of GGEs.

So, I tried to encapsulate that in the slide. If we're talking about volumetric equivalency pricing, we're basically saying that the price of one gallon of gasoline is going to equal the price of one gallon of E-85. And, again, I just -- E-85 is also what we refer to as an 85 percent blend of ethanol with RFG for California RFG or CARBOB, not RFG. So it's an 85 percent ethanol blend as opposed to what you would typically see at a gas station, which is more of a 6 percent blend, approximately.

So, on a volumetric equivalent basis you would have a gallon of gasoline sold for $2 for example, and the E-85 would be sold for $2 as well, per gallon of E-85.

If we were to present, which we will present, the energy equivalent pricing we're looking at the price per Btu of the product. So, we're basically, for our presentation, our method that we're using, we are equating the price of E-85 on a per-Btu basis to the price of gasoline.

So, in the example that I've provided here, a $2 per gallon of gasoline price would equate to $1.46 per gallon of E-85. And that's because E-85 has a lower energy content.

So you would basically take the $2 and divide it by the energy content or the number of Btus in gasoline, which is approximately 112,000, and then multiply that per Btu price by the number of Btus in E-85, which is approximately 81,000 or 82,000 Btus.

So that's why you have, on a energy-equivalent basis you have a lower price for E-85 because it has a lower energy content per gallon.

And then oftentimes it's valuable to look at energy in terms of a specific measure. You may, if you're looking over pricing, you may see comparative pricings of different types of energy in terms of 1 million Btus, or -- so if you're comparing the price of coal with the price of another energy source, oftentimes it'll be shown in terms of 1 million Btus, how much does it cost per million Btus.

In transportation there's often a reference to the gasoline gallon equivalence. And what we're saying there is we're placing everything in terms of the energy content of gasoline.

And here we have, for example, 112,000 Btus, and that's the lower heating value. And so the notion there is if we were to say we're purchasing energy and we want to compare two products. We could put them in terms of GGEs, or gasoline gallon equivalents, to see how they price up against one another on an energy basis, if we're buying energy.

So, in the example that I have here is for the volumetric price and where the impact of this GGE comparison, for the volumetric pricing in terms of GGEs, you would take the $2 per gallon of E-85. Because it has a lower energy content, you would divide that by 81,700. And then you'd multiply that to get the per-Btu pricing for E-85. And then you'd multiply that by the number of Btus in gasoline, 112,000.

And that would give you the price per GGE, or the price for gasoline gallon equivalent. Shown here as $2.74.

So, hopefully that explains GGEs a little bit, and the approach that we're taking for the volumetric and energy-equivalent pricing.

So, this is our low case forecast. The blue line, which is the volumetric pricing, if you were to compare that with what Ryan had spoken to earlier about the lower price of gasoline that we're seeing, those should be equivalent.

So the blue line here is volumetric equivalent price of E-85. And it would be equivalent to the gasoline that we're seeing in our low case for RFG low case.

The red line, although it says GG pricing, that's actually not correct. It's the energy-equivalent pricing. And that, because of the energy content of E-85 is lower than the volumetric price that you see here.

The dashed line in the middle is the average of the two and represents the central tendency of those two ranges, or two methods for determining the price of E-85.

Correspondingly this is our high price case. So, again, the blue line at the top represents our gasoline price forecast. It would also, on a volumetric basis, represent our high E-85 price forecast.

If we were to use a method that, again, looks at E-85 on an energy-equivalent basis we would come up with a value that would be represented by the red line here. And, again, that's an energy-equivalent basis referencing our high-price case for gasoline.

Again, the central line here is the average price for those two methods.

And that concludes the slides for E-85.

What I was hoping was that -- what I wanted to mention is that we're definitely looking for a discussion or direction or comments on which would be an appropriate method to use to capture the range of potential prices in the marketplace.

Certainly regionally the impact of supply of ethanol plays a role in the pricing of that E-85 in the region. But, on average, in California, if we wanted to come up with a forecast, should we capture it using the widest possible range, or should we look towards central tendencies? Those things are up for comment. Otherwise we'll be making that determination shortly, probably in the next couple of weeks.

MS. BROWN: Malachi.

MR. WENG-GUTIERREZ: Yes.

MS. BROWN: Isn't forecasting ethanol prices almost, I mean it's as difficult as forecasting gasoline prices, isn't it?

We've seen a lot of volatility of late. And I wondered if you factored in food-versus-fuel competition in your various methods?

MR. WENG-GUTIERREZ: We haven't explicitly added in the fuel-versus-food issue. Because we pegged it to our gasoline price forecast, those aren't really considered.

We could certainly go into an analysis of the feedstocks associated with ethanol, how those feedstock commodities pricing are changing over time. And then, you know, what are influencing those feedstock prices. And then trying to, you know, fill in our E-85 price forecast.

But, the decision we made, I think, is to take the approach -- and again, we were talking with the emerging fuels and technology office, and rather than do that, we decided to consider it in relation to gasoline gallon.

Gordon.

MS. BROWN: It would be a great issue to get some comment from other parties, I think.

MR. WENG-GUTIERREZ: Absolutely.

MR. PAGE: One comment on this. I think the reason we have stuck with this approach, this banding approach, for E-85 is because it accords very well with the data on service stations that actually sell E-85. It tends to fluctuate within this band and without any discernible direction or pattern necessarily. But it does seem to fall within this pricing band. So it's a kind of a market side confirmation of the approach.

MR. SCHREMP: Gordon Schremp, Energy Commission Staff. And just to expand a little bit on what Malachi was saying, and in response to your question, Susan, on the ethanol we have seen over the last three or four years, some market deviation prices.

Actual, you know, in response to changes in their feedstock costs, corn going up to a very high level, in response to natural gas prices going up very high, then coming down very quickly.

Yes, we've seen wild swings in their production cost inputs, but not necessarily a correlation extend to that of what they're selling in the marketplace.

Because what's going on with ethanol you have some other factors. You have a tremendous build in capacity in response to federal mandates. That's the renewable fuel standard.

And this is something that staff will be delving into deeper in terms of its potential implications on a market-clearing price.

As Malachi said, what will happen to ethanol pricing has a lot to do with the demand and the required mandates to use ethanol in the marketplace.

For example, the renewable fuel standard will likely result in 10 percent ethanol being used in California as soon as January 2010. It's a federal mandate expected to grow to 36 billion gallons by 2022. That is a big driver for ethanol use.

Now, how much will be in the E-85 market, or the mandated demand, will affect the E-85 prices. If, for example, the blend level in gasoline in just everybody's normal car, a non-flexible fuel vehicle, is higher than 10 percent. The USEPA is looking at this right now. Can that be E-15 or E-20.

If that is the case, then ethanol will likely be sold into a market and blended by refiners and other marketers at those higher blend levels at gasoline values, such as what we're seeing normally in the ethanol-gasoline relationship.

But if E-10 is the maximum and we achieve that in 2010, beyond that meeting federal mandates for renewable fuel standards in California will require, and can only be met through, E-85 sales. Therefore, a different dynamic takes place in that marketplace and E-85 may, in fact, command a premium just on a gallon-per-gallon basis.

Now how that translates into E-85 pricing at retail, Jim's right. We do see in other parts of the United States a divergence of pricing strategies. In California, how that ultimately plays out will likely be, in some part, dictated by consumer protections, if you will.

What is an appropriate form of price advertising at retail to give the consumers the maximum amount of information. And is that on a energy-equivalent basis so they can pull up with an FFE and then be able to just look at the price and say, oh, it's cheaper, I'll buy it.

If it's on a gas and gallon-equivalent basis that's certainly the fairest way to present information to a consumer.

So, is that the way the laws are, I don't know. That's a Division of Measurements and Standards issue. And certainly a consumer issue. But we have to keep that in mind because ultimately if, in fact, there is some advertising law that says it must be gas and gallon-equivalent pricing, then these two options, one of them becomes moot. There will be only one retail pricing option to consider in a price forecast.

So, just some additional information that staff will be working on these issues and presenting additional information to the Commissioners for their consideration.

MR. WENG-GUTIERREZ: Thanks, Gordon. And I was just going to mention that Gordon raises a very good question. I mean the policies that impact the ethanol adoption in California, there are many out there and many that are probably coming onto the table and be decided this year.

We haven't included all of those in our considerations, certainly, for the fuel prices.

The other thing is there are other technologies that could produce ethanol that could be used in the marketplace which we have not included as far as our fuel price forecast. You know, cellulosic ethanol, how that plays into the price of ethanol in California. We haven't necessarily considered that.

There's another comment.

MR. SHEARS: Yeah, I'm John Shears with the Center for Energy Efficiency and Renewable Technologies.

First, I just wanted to update in case people weren't aware of terms of blending more than E-10. Underwriters Laboratories and the Ethanol Fuels Association are sort of trying to release -- the Ethanol Fuels Association is working to see if they can get Underwriters Laboratories to reconsider their new position on fuel pumps, standard fuel pumps, so that basically they will not certify fuel pumps for anything over E-10.

There's still the outstanding issues of purpose-built pumping -- pumps for E-85 use, dedicated E-85 use. But, of course, those would work for lower blends.

So in terms of having that out there in the market, that's -- we're not contemplating that in California but it's an issue in other states.

Just to also put a finer point on some of the points that Malachi was just referring to, we, you know, probably as we get out to 2020 we're going to have federal policies besides larger regional policies that bite more on carbon pricing and not -- low carbon fuel standards are being looked at elsewhere in the United States.

Some that are consistent in intent with

what California is developing; some that are not consistent with what California is doing.

And also at the federal level, I think it's reasonable to expect that as we get out to 2020 we could expect some supplemental policies as it relates to, you know, the ethanol side of the biofuel pool. That's consistent with, you know, trying to deal with the climate issues.

So, you know, I would recommend using the banding, continue using this level high banding approach for the meantime.

MR. WENG-GUTIERREZ: Thank you, John.

MR. JANUSCH: We have Gary Herwick on the line.

MR. PAGE: Go ahead, Gary.

MR. HERWICK: Yeah, this is Gary Herwick, Transportation Fuels Consulting, speaking on behalf of the California Ethanol Vehicle Coalition.

A comment in followup to Gordon Schremp's comments, and also Malachi, here, with respect to the banding.

We had always taken a position that E-85 would have to be sold on an energy-equivalent -- at an energy-equivalent price in order to represent, if you will, a sustainable value proposition to consumers.

And, you know, we understand that that's not been the case throughout the rest of the country, as Gordon has already pointed out. That often it is either at a gasoline equivalent, rather a price similar to gasoline, or only offered at a slight discount to gasoline.

It has not been our experience that consumers, on a longer term basis, see that as a good value proposition. They figure out pretty quickly that they don't get the range out of a tank of E-85 that they do out of gasoline.

So, from our perspective there would have to be some involvement of perhaps the Energy Commission or state government to -- perhaps something like, and I was going to offer this in comments later, but perhaps something like a clearinghouse arrangement that could deal between suppliers and retailers to end up with something like an energy-equivalent price to represent a value proposition for the consumer.

I hope that helps.

MR. WENG-GUTIERREZ: Well, thank you for that comment. It might be interesting to bring that up in our infrastructure workshop that we're having, as well. But certainly if you could include those in your comments we'll consider them in the development of our range of prices that we'll be using for our demand forecast.

MR. HERWICK: Sure.

MR. WENG-GUTIERREZ: Are there any other questions on the phones? Sounds like no.

With that I think we have a couple of presenters if we're going to continue. Or the agenda does show that we were going to break for lunch.

MR. PAGE: Are you going to speak to the biodiesel?

MR. WENG-GUTIERREZ: I thought we had two presenters for the E-85.

Yeah, right, that's what I'm saying. I think this is our -- where we were going to -- oh, I'm supposed to continue and do biodiesel. Or biomass-based diesel. I apologize.

So, I wanted to start the biomass-based diesel discussion with just a discussion of the term biomass-based diesel. Oftentimes you've heard -- it's basically a relatively new term and it's an umbrella term that refers to many different types of biodiesel, renewable diesels and others.

All of these that are listed here are included under the umbrella term of biomass-based diesel. What I have highlighted here is biodiesel, because in the report and in the estimation of our price forecast for biomass-based diesel we are using biodiesel as the basis of that.

However, in the future, over the forecast period we are applying that price to other types of biomass-based diesels, not just biodiesel. We're applying that to renewable diesel, other biomass-to-diesel products, algae diesel, other things that could enter the marketplace.

We're not doing forecasts for each one of those types of biomass diesels -- based diesels. We're actually including them under this one umbrella term.

And I think that there is a tendency to go towards the biomass-based diesel definition at the federal level, so we're following that tendency.

So, for the biomass-based diesel pricing forecast we used, just very similar to the E-85, we used the high and low in diesel price instead of the gasoline for E-85, we used the diesel price because obviously that would be a better correlated value to diesel prices for a bio-produced diesel.

We looked at a historic run of months to gather a spread between a west coast biodiesel at rack price, and the California diesel rack price. And we used that spread, then, to calculate the forecast values.

In addition, we included of the federal fuel excise tax credit for biomass-based diesels, and we held that constant in real terms over the forecast period.

In addition to that, similar to the other methodology we used for gasoline, we also held real to state and federal taxes and fees constant over the forecast period.

So, the listing of assumptions are that the west coast biodiesel rack prices, primarily we looked at B-20, and that's how we determined our spreads, and what we are actually forecasting is a B-20 blend. So we looked at the west coast biodiesel rack prices and the California retail prices relationships. And we're assuming that that remains constant over the forecast period.

In addition, the federal excise tax credit of $1 we're saying will remain constant over the forecast period.

And then, as with E-85, the tax credits will remain constant. And then with E-85, as well, I mentioned, or the question that Susan had was have we really considered feedstock pricing. And what we're assuming there is that the feedstock market prices are not necessarily going to impact or affect the pricing of the biobased diesels as we provided them in the forecast.

So we're not really considering the feedstocks, themselves, and how they might impact the prices. We're assuming that what we're estimating should capture the range of potential prices for biobased diesels.

And that's what that second-to-last point basically says, is that again the range of values that we're presenting hopefully will capture all variations in the spreads and the feedstock prices.

The last item here is, it just says that the current federal excise tax credit will expire on December 31, 2009. We are assuming that it, again, will remain constant at $1 through the forecast period. That may or may not be the case.

But I wanted to put that item in there just to note that under current laws it will expire at the end of this year. However, if we are assuming that it will be renewed and that it will be extended through the forecast period. It has been renewed a number of times.

So, with that, this is biomass-based diesel retail price forecast. So the solid lines, there are two diesel prices, both in terms of 2008 cents.

So the solid blue line is the high diesel forecast. The solid red line is the low diesel price forecast for California. And then the B-20 high and the B-20 low forecasts are the dashed lines.

And I believe that is the end of my biomass-based diesel discussion. Are there any questions about the methodology assumptions or comments on the biomass-based diesel forecasts?

Are there any questions on the phones?

(Pause.)

MR. WENG-GUTIERREZ: All right. Doesn't

sound like there are any more questions.

So, just give us a minute here. We're considering breaking for lunch, because we know how hungry people are.

(Pause.)

MS. KOROSEC: Given our schedule for what we've got planned for speakers, I think this would probably be a good time to break for lunch. It's a little early, but it seems to be a natural breaking point.

So why don't we try to get back here at 12:30.

(Whereupon, at 11:13 a.m., the staff workshop was adjourned, to reconvene at 12:30 p.m., this same day.)

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AFTERNOON SESSION

12:19 p.m.

MS. KOROSEC: Thanks for your patience, everybody. I believe -- hold on a second while I grab my agenda. So we'll be moving on to -- actually, Jim, should I turn this over to you to introduce the next speakers, or do you want me to just go ahead and --

MR. PAGE: Oh, go ahead.

MS. KOROSEC: Okay, okay, so we've got Ron Lamberty from American Coalition for Ethanol, followed by Gary Herwick, Transportation Fuels Consulting. And I believe Ron is remote?

MR. JANUSCH: Ron and Gary are both remote.

MS. KOROSEC: Okay, great. So, go right ahead, Mr. Lamberty.

MR. LAMBERTY: Hi, everybody. Good to be talking to you. As I mentioned earlier to Gary here, if you couldn't hear me, I just got done with a board meeting so I'm happy to be doing just about anything else. This is kind of an intriguing subject.

Wanted to give you a little bit of an

update of where the ethanol industry is because there's a lot of news out there. And most of it that you hear is probably not the kind you like to hear if you're worried about the fuel prices and demand.

But we'll kind of walk through where the industry is, talk about a couple factors and then just answer as many questions as you have.

Hopefully Maurice Hladik of Iogen will be calling in, if he isn't on the line, and can make himself known, too. Iogen is a cellulosic ethanol producer, so if there's questions about what the status is of that industry and what the development's going to be, he is better equipped to answer those questions than me.

So, I'm just going to go through this presentation. There's only three slides here. Currently 221 completed plants, ethanol plants, in the U.S. Most centered in the midwest, but a little bit scattered outside of that. We've got a few in California, but still the bulk of it in the midwest.

One hundred seventy one of those are currently operating with a capacity of about 10.4 billion gallons per year, which is a critical point. Because right now our requirement for corn ethanol, which is what all of those are, is 10.5 billion. So there has to be some gearing up of those plants that are among the 33 that are closed sometime during this year.

And then there are still 16 that under construction. That number was 19 a few weeks ago. So there are still some plants opening up and starting production.

But between the two, the ones that are open that could produce ethanol either currently or on very short notice, you have about 12.7 billion gallons available.

Right now what we're going through is in addition to the economic downturn that everybody's seeing, you've also got just the math of creating more product into a market that also is going down in volume.

In 2008 I think the total amount of gasoline sold in the U.S. is going to be somewhere around 134 to 135 billion, meaning that with the ethanol portion taken out of that it would be about 125 billion gallons. That's from a margin that only a few years ago was closing in on 140 billion gallons of just gasoline.

So, in creating that much ethanol you also create a lot more available gasoline. The price has dropped, that becomes ethanol as a substitute for it, follows it, and so ethanol prices have dropped, too.

That, coupled with the volatility of the feedstock, the corn, which was very high in the spring and summer and dropped off dramatically in the fall and winter, that was a situation where people who bought corn at a high price and are selling ethanol at a low price are in a lot of trouble. They're among those 33 closed and among the large bankruptcies that you've all heard about or read about in the papers.

In addition to that, the plants that are still operating, there's some issues with tightening credit. And it's come from generally the things that everybody's seeing in all industries.

Some of that just having to do with the math. I was at a plant two weeks ago for their annual meeting. They've made all their payments. They have $3 million in the bank. But the covenants of their loan say they're supposed to have 5. Had ethanol prices stayed around the $2 range they would have 5 million in their bank. And yet, the prices dropped so the value of their inventory is lower, and all of these things are challenging.

One thing that's not on here that may be an interesting this is as we see the part of the Verason Group being sold initially at a price that's about 50 cents per gallon. If we have banks that go in and revalue some of the existing plants that are out there, and change those which were mostly built for between $1 and $1.50 a gallon, and refigure their worth at 50 cents a gallon, we may have some more credit issues.

Then we've got, you know, some of the issues that are in the press that are either real or imagined, in most cases they're somewhere in between those. You've got the issue of low prices of fuel now that have caused a little bit of complacency where people say, well, then, I guess maybe we don't need this stuff.

We've got the ongoing food-versus-fuel debate where last year there was a big outcry that the higher corn price was causing a lot of food price problems. That, and fuel prices, corn prices and fuel prices have dropped in half and food prices haven't moved that much. But it's still an issue among the public and among government. So that's an issue that we'll continue to address.

And then there's the corn-versus-cellulose debate. Basically I think most people know that in order to get to the numbers that we've got the renewable fuel standard, we're going to have to have dramatically increase in cellulosic production.

I think there's an attitude out there that maybe we could just switch to that tomorrow. And, as you all know, that's not necessarily the case. So it's managing expectations with those issues that's created some more challenges for the industry.

Ethanol prices, actually people have talked about them being, ethanol actually being higher than gasoline. And the discussion has been that ethanol is actually more expensive and frankly, like all other energy right now, ethanol prices are down about 90 cents from where they were about six months ago.

Now, on the other hand, ethanol is relatively expensive because as ethanol's gone down gasoline has gone down even more. And so we've got a situation where the ethanol price compared to the gas price seems high. Yet all energy's down and people are actually saving some money. And to some fairly large extent part of that is due to the fact that ethanol is in the marketplace.

And, again, that issue probably continues to weigh on the industry a little bit. But, you know, efficiency's improved both in raising feedstock and handling it, the amount of fuel that you can get out of a bushel.

And as prices normalize on the mercantile exchange and products are treated more in a market fashion, we think that that will moderate the situation we've got in the industry right now.

We'll say that as of today, if you're looking at the price of corn and the price of ethanol, that the price of ethanol at the plant gates, that most plants in operation can make some money today. You know, make some margin.

The issue is how much of a hangover that is out there from the time that they've spent, you know, paying a lot for corn and getting very little for ethanol.

So the industry is, in general, profitable right now. There are the dead issues that are going to have to continue to be dealt with and, you know, other issues that, of course, you're all talking about. And the federal government will be talking about, too.

So, with that, if Maurice is on here, I'd have him chime in. If not, I think Gary probably would be best to go next.

Maurice, are you on the phone?

(Pause.)

MR. LAMBERTY: He was just calling in from a car phone, too, so I'm not sure exactly how he'd --

MR. HLADIK: I just -- waiting for me?

MR. LAMBERTY: Yeah, yeah, there you go.

MR. HLADIK: I just got in here, um-hum.

MR. LAMBERTY: Yeah. Then basically then if you could speak to a little bit of what's, you know, where we are with cellulosic ethanol and sort of an outlook for what the production and what the costs are. And then be available basically for questions here.

MR. HLADIK: Sure. Do you want me to

start with that, or what?

MR. LAMBERTY: Sure, go ahead.

MR. HLADIK: Okay, good. Iogen's roll-out scenario, and then our scenario with our competitors.

First, we didn't produce any cellulosic ethanol from (inaudible) tanker truckload. The first truckload went out in April 2004. We've had several upgrades to that to our demonstration crop, which is about an acre footprint six stories high (inaudible) capacity.

And the most recent was a $8 million -- this past summer. So, we proved we could do it five years ago and we've been working on it ever since to get the cost down.

And we have our first plant. We've got options on land. We've got the money lined up (inaudible) half-a-billion-dollar plant in western Canada. And we'll close on the final design, we hope, in April. Final investment -- later on this year. Shovel in the ground sometime in early 2010. Full commissioning in 2012.

And then we would hope we could start to roll out. There may be a -- maybe even requires going public before we can really get investors in the kind of cookie-cutter approach. But that is our desire, just like (inaudible) in their plants. We hope to have a design that can be replicated easily.

Now, so that being -- it'll probably be the better part of five years before rapid deployment will take place with our technology.

Now, we have competitors out there who are making claims for things happening a lot sooner. But we still have yet to see any of our competitors actually making announcements such as we do that we shipped 50,000 gallons to Shell, and what-have you.

We do know that there's some people out there looking for cellulosic ethanol. They tell us we're the only one who can, you know, can immediately get 2000 gallons from us.

So, we are a bit surprised that some of our competitors, who have not yet demonstrated, are making claims that they will be commercial, you know, very very soon. (inaudible) they can do it, but I -- kind of the more you know, the more you don't know.

We've been doing it, and we found it challenging. That's the purpose of our demonstration plan. We certainly have the challenge, get on with -- and -- talking from the office here for a second.

So, the issue is how quickly can the industry mobilize. We are projecting widespread, you know, widespread roll-out -- the plants in about five, six years, is our prognosis.

We know BlueFire, they're in your midst. They have infinite feedstock supply. They're, you know, (inaudible). We've yet to see them announcing actual tanker truckloads of fuel going out of the demonstration size facility.

(inaudible) Company, they're commissioning their demonstration plant -- same capacity as ours.

So I really can't see the industry taking off. It's coming together and they've got their competition, but for the likes of us I don't see us really having large, you know, several plants under construction at once, but -- five, six years.

Another side of the industry that I spent -- I'm in Florida right now with the environment -- I am going to do the same thing in California, -- BlueFire with their (inaudible), but the feedstock situation, you know, for a typical plant to get a million tons of biomass. And that'll produce about 80 million gallons, which in the corn ethanol business isn't real garden variety. You got to have -- distillation, economies of scale are identical to the corn industry.

So, little tiny plants will not be terribly efficient. Places in the United States, or anyplace in world right now where you can get a million tons of biomass easily are few and far between from agriculture residue.

I've looked around Sacramento, pretty good -- straw, but a ton, if we calculate models, themselves, that there's maybe 600,000, 700,000 tons there, a really good start. But that is a huge block in California to raise for cellulosic biomass.

Everyplace I go, western Europe, certainly in Canada, throughout the U.S. the focus of biomass isn't there. And, you know, our concern is for rapid, full-scale roll-out. There will be a shortage of biomass unless, you know, we estimate better than close to 300,000 farmers averaging 1000 tons of biomass to reach the 2022 of 15 billion gallons.

There are programs coming into place that will be a real help to get farmers up to speed, turns our farmers up to speed in this industry across the U.S. with a real focus on dedicated biomass crops.

So basically that's my quick overview of the state of the industry and where it stands.

MR. LAMBERTY: Okay, I guess that's -- do we want to go to Gary, or do we want to take questions? How do we want to -- Gary, you do have a few comments, didn't you?

MR. HERWICK: Yeah, a few comments unless there are questions people want to bring up right away, I'll just go ahead with a few of those. It won't take me long here.

You know, I'll speak a little bit more directly to the IEPR, you know, where I think you're going with it.

The low carbon fuel standard require high volumes of alternative fuels that will exceed, you know, the federal RFS.

Probably more importantly to the California Vehicle Coalition, which I'm speaking on behalf of today, the volumes of ethanol that are likely to be required greatly exceed the volumes that can be supplied by 10 percent ethanol that'll be in California in 2010 and later.

And although there's been a lot of discussion about intermediate blends of ethanol, there has not yet been a waiver application submitted to EPA. And the data to support such a waiver is probably incomplete at this point.

This means to us that there are probably very large volumes of E-85 that will be required in the state to meet the low carbon fuel standard requirement.

Now, we feel that E-85 from corn-derived ethanol, you know, is an alternative fuel that can be supplied in the volumes and the timing that'll be needed under the low carbon fuel standard.

We also believe the concerns about carbon intensity assessments that have to do with land use can be resolved, such that corn ethanol could be a viable carbon reduction strategy, at least in the short term.

And we would cite the reports and comments that are available now around the low carbon fuel standard regulatory process, such as the recent report from the University of Nebraska at Lincoln, and extensive comments that have been submitted by the Renewable Fuels Association.

With respect to infrastructure there are currently 388,000 FFVs in California, I think, as of July 2008. There are 13 E-85 stations now, although, you know, just a year ago there was only one station. Certainly a lot of credit to the Air Resources Board and the Energy Commission for taking the necessary steps to get the infrastructure development started.

There is a forecast now that we could have as many as 23 stations by year end. And suppliers such as Propel Fuels, Nella Oil and Pearson Fuels are leading the way here in supplying E-85.

As I said earlier, in order to be a sustainable alternative fuel, and what I mean by that is that it provides a sustainable consumer value proposition, it needs to be sold at an energy-equivalent price to gasoline. That is about 75 percent of the price of gasoline, as I believe Malachi already talked about.

Although that hasn't happened at other U.S. locations, those are consistently occurring in other U.S. locations. You know, it is possible that it could get to that price, but it might be government incentives.

But another possible way to deal with that might be for the Energy Commission to act as a clearinghouse to work between suppliers and retailers. And possible short-term incentives for the fuel might be needed, as well.

FFVs, there is an availability issue in California that needs to be resolved. Currently, as of 2007, the state of California has about 25 percent FFVs per 1000 vehicles, compared to other states.

Manufacturers are now currently certifying FFVs to the SE LEV and PZEV standards. As we look in the future in California, that makes up probably at least 70 percent of manufacturers' sales volumes, perhaps up to 100 percent.

There are currently unresolved technical issues. And there are currently not incentives for manufacturers to overcome them.

Auto manufacturers, as I'm sure you're aware, have made commitments by 2012 to produce 50 percent of their production as FFVs. However, in order for California to take advantage of that, there needs to be steps to resolve those technical issues, which would involve cooperation between the Air Resources Board and the manufacturers.

Incentives could also be helpful in offsetting the additional cost of FFVs.

As far as the California Ethanol Vehicle Coalition is concerned, a public education component would be needed, as well, to increase the sales of E-85. That could include perceived consumer risks that have been out there and discussed, the energy content and fuel economy issues that we've already talked about. The so-called energy balance issue, the food-versus-fuel issue, land use concerns. Just to overcome some negatives with respect to ethanol and E-85.

California Ethanol Vehicle Coalition, if we were going to participate in this, which we would be happy to do, would require some additional funding, as well.

I guess that concludes my comment. If anybody has any questions --

MS. KOROSEC: Are there any questions from parties in the room?

MR. PAGE: Yeah, I have questions. Jim Page, Energy Commission. You mentioned incentives might be needed for the fuel side, as well as the clearinghouse side. Could you elaborate, give us some detail on what, you know, the formulas incentives would take, or the amount or magnitude? And a little bit more on the nature of this clearinghouse.

MR. HERWICK: As far as incentives I'm not really prepared to talk about the amount, I don't think, at this point. We'd be happy to work with you on that to discuss, you know, how we might put that together.

We think eventually, as I said, that to have sustainable consumer value proposition that the fuel needs to be sold at an energy-equivalent price to gasoline. Perhaps to get things going we might need some incentives. I'm not sure what that is.

With respect to a clearinghouse, the idea, you know, is not mine originally. But I think that the Energy Commission worked on such a concept years ago on the M-85 program. Where it worked between retailers and suppliers of the fuel to insure a viable market price that I guess might be a way. And that idea might be worth looking at again.

MR. LAMBERTY: And this is Ron, again.

One of the things that I'd address, I think, there's been a lot of discussion over the years about the cost of changes in the vehicles and the cost of the fuel, itself.

What we have seen has been the biggest hurdle to get over in the E-85 distribution equation has been the cost of pumps, the petroleum marketers. Given the fact that over 90 percent of the stations are owned by individuals.

I own a couple of gas stations, myself, and the issue has never really been how much is available for the pumps, but how much is left to pay for, when all of the incentives are gone.

We have a federal law that was I think just included in one of the bills that went through within the last couple of days that we increase the amount that a petroleum marketer can get in the form of a tax credit for putting in E-85 infrastructure.

But it's based on just the E-85 portion of the pump. And as such, it doesn't offset anywhere near enough of the upcharge that one would have to put in the equipment with the new UL standards.

So we're working on a federal level with

NADC and others trying to get that to apply to the pump, itself.

Barring that, there might be some incentives that would be made available to the petroleum marketers to put in the equipment that handles this. Because in some cases, and I know the equipment there is much different than the rest of the country, but it's, you know, we've gone from a pump that a ballpark figure costs $15,000 or $16,000 to one that costs $25,000. So it's a substantial upgrade to just add that one product. So that's something that will need to be addressed somehow.

MR. PAGE: Thank you.

MS. KOROSEC: All right, are there any other questions? Do we have any questions from the WebEx? Is there anyone on the phone who would like to ask a question?

MR. HLADIK: I have a question. Maurice Hladik, Iogen. There's increasing evidence out there that the -- well, starting with Volkswagen, and that's -- my company, that with their new high-compression, turbo gasoline engine they advised us that E-85 they get only an 8 percent loss in mileage. And after -- 30, 40, 50 percent blends, they're announcing gasoline.

And -- certainly has in -- Minnesota, that seems to be having the oxygen content in the ethanol -- high-compression engine may not mean that the energy content is the only factor in pricing, but maybe the mileage is not quite as bad as the energy content would indicate. This is an observation --

MR. LAMBERTY: Gary would probably be the better one to answer that. I know in specific situations we've seen that. But across the board, in the legacy fleet, the mileage is what the mileage is. And I think, you know, it's good to focus that for the vehicles that come out in the future and we're going to be using more ethanol, there are things we can do to improve that efficiency.

MR. HLADIK: The legacy fleet will never be more than 10 percent ethanol. And so, any day now. We would hope as time goes on that this would be either debunked totally or become a factor that motorists could understand.

MR. HERWICK: I think that's probably a good way to put it. Let me make another comment, if I could, that Maurice might be able to address.

You know, there's been some discussion about how the existence of the corn ethanol industry will help with respect to infrastructure and having the plants available, to move toward cellulose ethanol production.

And there have been varying views expressed in California in the low carbon fuel standard regulatory process.

Maurice, do you have any comments on that?

MR. HLADIK: Certainly, I do. You know, if we were in cellulose-to-ethanol industry starting to develop our technology, we had a new fuel that the car companies and consumers and petroleum companies didn't know anything about, or had no use for, we would be really really in a very difficult state. The plants to the corn industry, those issues all might be behind us.

Secondly, we are very concerned that there's any slippage in government for the corn ethanol industry, we're going to be tarred with the same brush. That investors are going to say ethanol is ethanol, corn industry got launched because of government incentives and support.

And all of a sudden that support is

either partially or more than partially withdrawn. That would be a terrible statement to the investors of the cellulosic ethanol industry. And wherever we can -- we'd like to save this.

MS. KOROSEC: All right, if there are no other questions I think we're ready to move on. Malachi.

(Pause.)

MR. WENG-GUTIERREZ: All right, so again, this is Malachi Weng-Gutierrez with the fuels and transportation division. I'm going to be talking now about electricity and the electricity price forecast that we've included in our report.

The first slide that I have here is basically representing some of the historic prices for electricity that are observed in California. This is federal numbers that are reported to the EIA, I believe.

And they've broken them out into different sectors. And so for residential rates, 2008, you see that it's a little above 14 cents per kilowatt hour. All sectors in 2008 looks like about 13 cents per kilowatt hour.

And then transportation, the component

that they have identified as transportation is shown at slightly over 8 cents per kilowatt hour.

There are other sectors that they have reported values for, industrial sectors and commercial sectors and others, which are included in that all category, which is that solid blue line.

The transportation sector was something that they pulled out from the other category in 2003, redefining some of the categories and the pricing and how they've aggregated those numbers.

So in 2003 they pulled out transportation. And what that primarily represents is electricity pricing for electricity sold primarily to public transportation organizations, transit districts and things like that. That wouldn't necessarily reflect what a residence would see.

And that was part of the reason why I want to bring this up, is that although there are reported historic numbers for transportation, those might very well be different than what you would see if you or I were to buy a plug-in hybrid electric vehicle or a full electric vehicle.

So there's a wide range of prices, and

these are the ones that have kind of been out there at the national level, or reported to the national agency for California. So, again, I just want to set the context of the conversation.

The methodology we used to arrive at our price forecast includes looking at the existing electric rate tariff structures for alternative fuel vehicles that exist today. When those tariff rate structures, themselves, do not exist, we've looked at what discount rates are provided by the utility companies.

And we primarily looked at five different utilities in California which, looking at the 2007 consumption numbers, covers over 90 percent of all California residential consumption.

So, we felt that it was a fairly decent representation of what a consumer would likely see as their rate if they were to buy the vehicle and start charging it at their house.

The second bullet point, I just want to point out that what we did do was a marginal analysis. And what we looked at was if you were to buy an electric vehicle, or plug-in hybrid electric, and you consumed an additional amount of electricity over and -- above and beyond what you would normally consume, how did that affect the rate of electricity, the charge, the price of electricity that you have at your house.

So, in some instances, the utility tariff rates are based on a time-of-use, and they also have a tier pricing structure based on how much you consume in a given month. And we've taken all of that into consideration in our estimates.

Then what we did was after we've identified those kind of values for, given that the marginal analysis and the existing tariff rates, we weighted the average price to all of California based on actually not 2006, but 2007 statewide consumption levels.

And so again what we did was if PG&E represented 33 percent of all consumption in California, we weighted the price that we had estimated for PG&E to be 33 percent of overall, the price, the average price that we would see in California. So it was a weighted price based on consumption.

And then the last item I wanted to note here in the methodology was that we kept most things fairly constant over the forecast period.

We started from a snapshot of what the tariff rates look like today.

And then in order to generate a forecast over the period of time that we were looking at, we held the nongeneration costs fairly constant. We allowed them to increase over the forecast period using, in constant real terms for nongeneration costs.

For generation costs what we did was we took the commodity-based approach. We assumed that the generation costs would increase over time with the increase of a specific commodity. And what we had done in the 2007 IEPR was really look at natural gas prices over a forecasted period, how they changed, and then how would that then influence the price of generation.

And that was our way of trying to get at how are these existing tariff rates going to change over time. And so that was the method we used.

This is the price forecast, itself. You notice, the electricity prices, which are showing the EV high and the EV low are the solid lines on this graphic, on this figure.

So the highest value here is that solid

blue line which represents the high EV rate that we estimated over the forecast period. And then the dashed line is the equivalent, or the gasoline value. The EV rates here are in gasoline gallon equivalents, which I briefly described earlier, putting it in context of how much, again gasoline gallon equivalents as a gauge.

But what I want to point out here, also, is that we're not considering the efficiency of the final vehicles. And I know that for many of the alternative fuels, and particularly for electric vehicles, the efficiency of the vehicles, themselves, will change the effective price that a consumer will pay for a unit of fuel. That hasn't been incorporated into these figures, they haven't been incorporated into these numbers, but they will be incorporated into our demand forecast.

The vehicle fuel efficiency values that we're going to be using that will be derived from the vehicle attributes contract we have, and those will be part of what we have as inputs that will get to the final consumer price of transportation fuels and those sorts of things. But that's not something that we are including in this price forecast. And I don't believe we've actually included it any of the other price forecasts that were presented today, either.

The bottom two dashed lines, the ones at the very bottom of this figure, I put in just sort of to represent what you might see in today's market. This is basically PG&E's offpeak rate which starts at about, you know, fairly low at $1.30-something gasoline gallon equivalent. And then stays pretty constant over the whole forecast period. And I just wanted to present that as kind of the low value of electric vehicle, what you might see as a low value for pricing for electricity in an existing tariff rate.

Now, this doesn't include any kind of metering rate. There is a monthly metering rate. Or a customer's service charge. We didn't include that in that number.

MR. JANUSCH: Malachi.

MR. WENG-GUTIERREZ: Yes.

MR. JANUSCH: We have a question from David Modisette.

MR. WENG-GUTIERREZ: Excellent, okay.

MR. JANUSCH: David, are you there?

MR. WENG-GUTIERREZ: Go ahead, David.

MR. MODISETTE: Okay. Yeah, this is

Dave Modisette with the California Electric Transportation Coalition. I just had a couple of comments on this.

I guess, first of all, just to emphasize what Malachi said, that these costs in cents per gge do not include the efficiency of the vehicle. And the way that is traditionally incorporated in an analysis like this is in one of two ways.

The first way is to include in the calculation some kind of a ratio which reflects the efficiency of the vehicle. This is called an energy/economy ratio. And for electric vehicles it varies between 3 and 5, depending on the vehicle. In the Energy Commission's full fuel cycle analysis they use an energy/economy ratio of over 4, about 4.1, I believe it was.

So if you were to apply that ratio to these cents per gasoline gallon equivalents, you would essentially divide these numbers by 4. So you can see the equivalent gallon cost once you factor in the EER, would be a little over $1 a gallon.

I guess, you know, my suggestion would be that in the table in the staff report and in the analysis that you use that EER. Another way to do it would just be to express everything in cents per mile, which is the way the Energy Commission's full fuel cycle analysis actually did it. And using that technique you inherently incorporate the efficiency of the vehicle.

It seems to me that's a much more meaningful way to display these numbers and to explain them to people.

The second comment I had was that Malachi and I talked last week, we talked about the various utility prices for electricity, for transportation. And most of the utilities have fairly low offpeak rates for electric transportation.

Southern California Edison does not currently. However, it has filed for a revised rate in its current ratecase, which is ongoing right now. And assuming that is approved by the Public Utilities Commission, then their offpeak rate would drop to 10 cents per kilowatt hour.

And so we're expecting that to be approved probably in the summer to fall timeframe.

Thank you very much.

MR. WENG-GUTIERREZ: Thank you, David. Yeah, we did have these conversations last week, and I did want to point out that these are EEGs and we haven't included the vehicle efficiencies.

Dave mentioned the EERs and the full fuel cycle analysis. And how they've handled it on a per-mile basis. And I agree that if you wanted to represent the price of travel on a per-mile basis, or if you wanted to include an EER, we could do that. But that isn't how we've presented any of the other alternative fuels today. And to be consistent with the other analyses, or the other presentations today, we've kept it in a GGE base -- on a GGE basis.

Now, in the final analysis we will be including the efficiency of the vehicles as a value to -- you know, the consumer is going to see a price which represents the price on a per-mile basis that they would, you know, they would have to take if they were to buy a vehicle like this, that it would add to the utility of the vehicle.

So, the vehicle attributes will include fuel economies. The fuel economies will be considered in the final demand forecasts, in the consumer preferences for their vehicles that they adopt. And so that should capture that comment.

And actually the second comment that

Dave made was regarding the existing rates for Southern California Edison, and that actually is a good segue into my next slide.

What I have here is for the analysis that we performed I took the offpeak tariff rates and showed them here for the five utilities that we've evaluated. And then their corresponding consumption.

So the red bars in this graphic show the proportion of the statewide residential consumption associated with that utility.

So if you were to look at the right you have PG&E. Their consumption is, you know, over -- just under 35 percent. If you look at Southern California Edison all the way to the left, their consumption on a statewide basis is also around 33 percent.

And then if you look at the other bars, the blue and the green, and then the multicolored bar, for PG&E you see the different rates, the cost cents per kilowatt hour that exists in today's EV rates.

So I wanted to show this just to represent, or to illustrate some of the numbers that we've used to create our estimation.

So, as David had mentioned, Southern California Edison has a large amount, or a large proportion of the statewide residential consumption is in Southern California Edison. Their rate is fairly high compared to SMUD or LADWP. And we're estimating, which includes the metering and service charges, at over 20 cents per kilowatt hour.

And so that does play a role in our estimation. If in the revised rate structures they are lowering that to 10 cents per kilowatt hour, I would imagine that would have a significant impact on our forecast of prices. And we would be happy to include those in our price forecast.

I guess the other thing -- well, I'll get to that in the assumptions. So the assumptions that I wanted to go through were that, the first is there's a lot of discussion about the charging profiles, when are people charging.

As I noted in the previous slide, what I was looking at was the offpeak prices. There are onpeak prices. And certain utilities have shoulder-peak prices, or partial-peak prices.

So we basically used the assumption that

88 percent of the time people would be charging offpeak. And that these 88 percent offpeak, 8 percent partial peak and 4 percent onpeak hours charging profile comes from a PG&E study that was done awhile ago. And that's where we got those numbers.

If we change it to 100 percent offpeak, or however, we could do that. I don't know how much that would actually change the final values, but that was something we could certainly look at.

The specific charging profile was something that we could try to look at and find sources of information, studies that had been performed, to show what were consumers actually -- when were they charging. And to get a better sense of that. But we felt that this report that PG&E had produced was a reasonable representation.

The next assumption that we made was, I know for different utilities they have dual-meter and single-metered rates. And what we tried to do was capture when could a consumer have a separate meter, or when would they be forced to use a single meter.

And that plays a role, certainly for PG&E where you have a tiered pricing structure.

If you're forced to have a single meter then that does, as I mentioned earlier, it adds the additional electricity consumption from your vehicle onto your household consumption, which raises the price of your overall electricity fairly significantly.

So, in situations where you have dual metering opportunities that may be the best option for you.

Now, depending upon the rate of your consumption, how much consumption you have of electricity for transportation purposes on that second meter, you may have a separate metering charge and that might still be expensive on a per-kilowatt hour basis. But, by and large, if you're on a tiered pricing structure like PG&E it's probably going to be cheaper to go with the separate meter.

So to try and capture that what we did was we contacted different counties to figure and ask whether or not you could install separate meters in a household for electric vehicle use. And there are some counties that don't allow it, like San Francisco County, for example, does not allow a separate meter to be installed.

And so what we did is we basically did not use that second metered rate that PG&E had for that county. And what we did for those counties that we didn't collect information, we used the ratio of the information we did collect on those counties.

So, for example, as it's stated here, 30 percent of the PG&E customers were assumed to be using rate A, which is a single meter. And then the remainder were using rate B, which is the dual-metered rate.

So in counties that we couldn't collect information on we used a 70 percent dual-meter rate, and a 30 percent single-meter rate just as a representation.

Now, there may be other sources of information, or if there are comments by participants that show that there are other options, other technologies that might get past this dual-metering issue, that would be great to have as information.

I know that in recent meetings with the CPUC they've talked about smart meters and how they might impact the application of different tariff rates. And so to the extent that we can get feedback today on how a smart meter might impact the application of different rate tariff rates to the household, that would be very helpful.

The next bulleted assumption here is that we have not included any installation costs for a second meter in our evaluation. So we assume that those costs are separate. They're borne either by the consumer or the utilities or someone has to bear those costs.

Now, we presume that if those installation costs for a second meter are high, then it might inhibit the adoption of a dual-meter situation. But, again, that might be circumvented by a smart meter and some of the capabilities that are associated with smart meters. But that would be something that we would like comment on today.

The average monthly increase in electricity usage was assumed to be 170 kilowatt hours over the normal usage. And we arrived at that number by assuming that a vehicle -- primarily we're looking at PHEV 40s.

And we took a range of efficiencies that we had seen from different literature. And then also a range of miles that someone might travel over a given year.

And we looked at the Advanced Energy Pathways work that was done in the PIER group. They had some estimates about what would be a likely per-year mileage traveled, VMT. And so we included all those things in our estimate and we came up with this value of about 175 kilowatt hours.

Separate from that we had other staff in the emerging fuels and technologies office perform an analysis looking at electric vehicles and how much they might consume.

They came out with a range, 175 is basically at the low end of their range, but we felt that if we wanted to really show a price forecast on a per-kilowatt-hour basis, we could use the lower end of theirs, as well as what we feel are going to be early market entries, which PHEV 40s and PG&E 20s, that seemed a reasonable value to us.

So if there is another estimate for overall consumption that might be estimated, on average, for California, that would also be helpful. Or even a different methodology for coming about that estimate would be helpful.

And then as I said before, we used the electric vehicle rate structures when they were available. And then in those instances where they were not available, we used the discount rate. There were some utilities that had discount rates that were not separate tariffs, but you got 2.5 cents discounted off of our per-kilowatt-hour rate.

So, that is the last slide I had for the electricity price forecast. Are there any questions or comments in the room?

Are there any questions or comments on the phones or online?

Okay, if not then I'm going to hand it over to Sven Thesen with Better Places.

MR. THESEN: So, I'm going to begin, how many people here have a cellphone?

MS. SPEAKER: You need to talk into a microphone, I'm sorry.

(Laughter.)

MR. THESEN: So, how many people here have a cellphone? And how many people here charge it at night? And how many people here use it during the daytime? Okay, good. And we're okay with that, we're using electricity offpeak, we're using the cellphone during the daytime.

And we're buying, in general, a plan that you selected, right? You said I will be talking for so many minutes per month, that's the plan I'd like to pick.

So if you talk a lot you're going to pick the 500 minutes per month. If you talk a little, it's going to be for emergency use. Is everybody okay with how their cellphone -- anyone here doesn't have a cellphone? Okay.

But everybody else is okay with how their cellphone business model works. You charge it at night, you pay for what you use. Keep that in mind, because that's actually really simple.

Because what I want to talk about is something far more complex, and that is our addiction to oil. Our addiction to oil is driving climate change; it's driving problems with air quality; it's driving balance of trade problems. Some would argue it's driving tariffs issues.

If only the problem of our oil addiction was as easy to solve as our cellphone. Well, the company I work for, Better Places, has the simple mission of ending our oil addiction beginning in the light-duty transportation sector. And I'm going to get to how that relates to electricity prices. And by the end of it I hope to put smiles on your faces.

Our goal, as I said, is to end our oil addiction through the use of fully functional, dedicated electric vehicles with unlimited range, using renewable power.

We sit between the electric utilities and the car manufacturers. We don't do either. We don't make electricity and we don't make cars. But what we do is the last couple yards between the plug and the car. We enable that. We solved the chicken-and-egg problem of infrastructure for electric vehicles in a cost effective manner.

Because in order to break our oil addiction we need mass adoption of electric vehicles.

So, the two historic problems with electric vehicles has been range and cost. Cost because batteries are really expensive. We break that cost barrier by Better Place owning the batteries. And there'll be a pop quiz after this when I finish. And that's the answer to question one. Better Place owns the batteries.

You don't have to worry about changes in chemistry or the batteries wearing out, because we own those batteries. And they are expensive batteries.

For range, because we own the batteries we can exchange the batteries. The batteries are exchangeable, so we have battery exchange stations, a few, set up so you can exchange the batteries when you're on your way to Tahoe. Because the cars have a range of about 100 miles.

How many people here have children? How many people here have ever changed batteries on an electric toy? Do the children care about the batteries or the toy? Where is the emphasis? They don't care about those batteries.

Just from a mindset perspective, let go of the batteries. You own the car, you lease the car, however your car's done. And then on that cellphone model you pay a subscription fee for use of the batteries, for use of the infrastructure, the battery exchange stations, all the charge spots that are located around.

Because we use renewable power, that's what we put into the vehicles as an energy source. We're increasing the demand for that renewable power, and this sits above any renewable portfolio standard. So we're aiding that demand for renewable power.

How does it work? Again, we provide the infrastructure. We sit between the utilities and the carmakers. We provide charge spots, battery exchange stations. And we own the batteries, themselves. Carmakers make batteries -- make the cars, I'll get to there in a second.

One thing we do provide is provide from a little sweet sauce on the vehicle. We call it autowest, which makes the driving and electric vehicle just that little bit more fun. And it talks to you and tells you that, you know, your son drove the EV at 200 miles an hour down the hill last Friday, or where they went. Things like that. If you want that information. And, again, we use renewable power to put into the vehicle.

The cars. These are not golf carts. At some point in time I'm going to airbrush my entire family in one of these vehicles, because they are fully functional sedans. We'll have sport utility vehicles, we'll have sports cars. And right now Renault Nissan is our first partner in making these fully functional EVs.

Renault Nissan crossed the ZEV line, or

ZEV war, so to speak, to make EVs on the order of hundreds of thousands. Right now they're retooling a plant in Turkey to make on the order of 100,000 EVs for Israel and other countries right now in Turkey. Sedans. They're the Megane, if anyone's familiar with them. But they're real cars for real people; range is about 100 miles; top speed is 80, 90 miles. And the sedans hold five people; the SUVs are just like SUVs. And they have exchangeable batteries.

So, charge spots. We hope to put in between two and three charge spots for every electric vehicle deployed or bought into the network. And these charge spots are J-1772 standard. That's the plug size, so we don't get to the old, anyone familiar with the zero emission vehicle wars, where we had different plugs to charge the vehicles. So anyone with the standard J-1772 plug can charge at one of our charge spots.

And you say, why are you putting in so many charge spots. Obviously, one at home, one at work, and then movie cinemas, grocery stores, the big-box stores. And they say, why you putting so many charge spots in. It's because we want mass adoption.

And there are people out there that realize, and it's okay, we're taking the range of a normal gasoline car, 300 miles, down to 100 miles. But we're putting in all these charge spots so you can charge anywhere. It's cheaper than sending everybody to therapy. Just better to have lots and lots of charge spots.

And again, Tesla, if they have a J-1772 plug, a Chevy Volt, a plug-in hybrid, they can all use these charge spots if they're participating in the network.

The battery exchange station. Hundreds of thousands of charge spots. Only a few battery exchange stations. But look at them as gas stations, but not one on every corner, just one on the corner.

You'll drive in and less than five minutes your battery will be mechanically removed from underneath the car and a new one put in. Now, within the battery exchange station we can charge the batteries in less than an hour, so we don't actually have to have lots of batteries there. Because remember, conservation -- you put one battery in and you get one out, and you drive on.

Look at it as Monday through Friday you're charging at home. And you may be charging at work. But on the weekends when you want to go skiing, then you'll use a battery exchange station to get you to Tahoe.

Now, from a customer perspective, how does this work? You buy the vehicle, and we have expectations of the electric vehicle costing on the range of the same as its internal combustion engine version roughly.

And then you sign up for a subscription plan for us, depending on how many miles you drive. And obviously the more the number of miles, the more you're paying. But your actual mileage cost drops down. And that cost is fixed for the number of years you sign up for. Just like a cellphone. So your bill is constant.

And we pay for the renewable power going in through a submeter on your house, and going out to the vehicle. So anyone can charge at anyone else's house that is on the network. I can go to Malachi's house and plug in; he can go to my house and plug in. And we know what vehicle number that talks to the charge spot there.

So it doesn't matter. And because it's

on a submeter we talk to the utility, the bill, the cost of that electricity never shows up on his home bill. His home bill can fluctuate as it does now. Doesn't get involved in the tier structure, doesn't get involved in adding to his additional cost. It's all the cost that we bear as part of the subscription that Better Place is offering.

Now, the key thing that might, as an ex-PG&E employee that is concerned about impacts of electric vehicles on utilities, is the service and control center. Just like the cellphones know exactly where we are -- all are right now, we will know where our vehicles are and how much energy they used the night before. And how much energy they used the week before. And be able to project how much energy we're going to use in the next minute, how much energy we're going to use in the next hour, for the next day.

So we can do things like avoid charging onpeak, because we know generally how far people will need to drive. And we can harvest intermittent renewable resources like wind.

So the week aggregate, and this is the key thing that the person who sits in the middle, between the utilities and the cars, can do is aggregate all this information. It's not a onesy, twosy, 1 or 2 kilowatt hours. It's on the order of megawatts. We aggregate this information and feed it back to the utilities.

Israel is the first place we're launching. We raised $200 million to install infrastructure in Israel in 2007. And we're installing this infrastructure right now. And, of course, the Israeli electric company got a little concerned about what are we going to do. What are the impacts of the system going to be.

So they looked at three cases. One is what we call ad hoc charging, or convenience charging. You come home 6:00 in the evening; you plug your car in and you start charging immediately.

Now, here were are at the California Energy Commission. Is that good for our electricity grid, charging at 6:00 onpeak? No. Okay. We don't want to do that.

How about the time-of-use? You have a time-of-use rate which the utilities have right now. And percentage, because the economics when you push the charge offpeak. Looked at that.

And then we looked at this Better Place

charging model where an aggregator controls the electric vehicle charging for the benefit of the grid and the users. And they looked at transmission, distribution and generation.

The worst case, under generation, they'd have to add roughly close to five coal-fired plants, 500 megawatts apiece, to provide the generation of that onpeak charging. And add a whole lot of transmission and a whole lot of distribution wiring. On offpeak it was less, but still they had to build additional generation.

But on the smart charging where an aggregator controls that charging for two million vehicles they had to add no generation. No additional transmission, and just a moderate amount of distribution wiring to address those 2 million EVs.

And again, it's because we're humans and we don't tend to do things at night, right. Who was up at 3:00 this morning? We don't use electricity that much at night. We use a lot of it during the daytime, particularly onpeak. That's why it is a peak, because we're all using it.

So if you can time your charging to do

it offpeak, there's lots of available capacity from a generation, a transmission and a distribution perspective.

There was a study roughly two years ago just looking at plug-in hybrids by Pacific Northwestern Lab. I like this study, because we're talking about electric rates.

And they said, well, what would happen if we added a couple hundred thousand plug-in hybrids, you know, those sort of 20-mile range electric vehicles, and then they go to gasoline.

And they said, well, let's look at a couple of electric utilities and look at their rates. Because you can time the charging, you can control the charging, you can aggregate the charging to offpeak they said, we can drop the cost.

It wasn't very much in the case of Cincinnati Gas and Electric, it was less than 10 percent. I don't know. Who would like 10 percent off their electric bill? Anyone say no to that?

But look at San Diego Gas and Electric. That's not that far away from here. By adding 1.1 million plug-in hybrids, and there's roughly 30 million cars in California, so there's ample room.

They were able to drop their electric bill from 204 to 251. That's cost per megawatt hour. But that's a considerable savings.

So when we talk about EVs, depending on how you charge them, is what's going to drive the price and the impact to our electrical grid and to our environment.

This is Denmark. Denmark is our second country that signed up with the Better Place model. Two weeks ago -- no, a week ago last Tuesday, today, we raised $133 million to install infrastructure in Denmark, in partnership with the Danish utility.

So this is a 24-hour load curve. It's called in Denmark, they do more things in the morning to get their houses hot, so that's why California peak, of course, being 6:00 in the evening, they have a morning peak. And their wind power, which is the green line underneath, again sort of like California, correlates to nighttime wind.

Is nighttime wind useful? No, not really, because again, the demand is during the daytime.

If you were to add 20 percent of their

light-duty fleet, that is 400,000 EVs, that represents roughly 3 gigawatt hours of electrical use. And because you can control the charging of those vehicles as an aggregator, we decided just to put it in from 1:00 to 4:00 in the morning. Because that's when most people are going to be to sleep, and their vehicles are going to be parked. And we can control that charging.

The good news, everyone says charging takes, you know, six to eight hours. That is if you run the battery pack down to zero. But people generally drive less than 40, 50 miles. And that can be done at less than three hours charging.

So you can hold off charging until wind arrives. That's what Denmark's planning to do. Right now Denmark pays Germany to accept their excess windpower. And they want to double their windpower capacity.

In California we've had instances where the cost of electricity at night has gone negative. They've had to pay customers, in essence, to take that electricity. And they've also had cases where they have to thin wind turbines. So this is wind in Denmark.

It's a two-week curve. The light blue,

the middle curve, is Monday through Friday, then Saturday, Sunday demand drops off. And the dark blue is the current wind generation. The dotted line is what they hope to double to.

What are they going to do with all that extra electricity? What they're planning on doing is harvesting, through the use of electric vehicle batteries in the car, that windpower at night. And then during the daytime taking one or two or five miles, they call them kilometers over there, out of each person's battery. Reducing their range by a couple percent -- you wouldn't notice it -- and uploading that power during the daytime. Because you can do that, that's called vehicle-to-grid.

So not only will be able to harvest energy, electrical energy, when it's really cheap. But we'll be able to put it back on the grid when it's really expensive. These are things you can do when you're a aggregator of all these electric vehicles.

So, let's talk about wind power in the U.S. This was from The Economist just last week. And I am quite proud to be here, because the U.S., again, is a leader in windpower.

But in California, where we plan on going to 33 percent renewables, how are we going to get all that windpower, when it blows mainly at night, back to when we need it? And electric vehicles are one of the few loads that you can time the charging to harvest that wind.

So we see electric vehicles, the cost of electricity for those electric vehicles, actually dropping. If you can put in some sort of dynamic pricing system working with the Public Utilities Commission, so that electric vehicles can harvest that windpower, and capture those economics.

Better Place. We're a startup, roughly two years old. Founded in Israel. Raised $200 million there to do Israel. In January we got Renault Nissan to run across and join us to make vehicles for us. And we're talking with all the other automobile companies right now to make vehicles for Better Place.

As I say, we launched Denmark; we've launched Australia, California and Hawaii. And, again, we just did Canada, part of Canada, one of the provinces. And raised money for Denmark. We're moving forward.

So when I think about electricity

prices, I think about how we have to make them flexible to address the economics of intermittent renewable energy like windpower.

And I think about the future of my kids and how we all have to work to make a difference. This is Sophie and Genevieve, and they're watching us.

Thank you. Any questions from the phone? Great, Sophie and Genevieve say I have to go home to look after them, so thank you very much.

(Pause.)

MR. PAGE: Next will be Gary Yowell on compressed and liquefied natural gas price forecasts.

MR. YOWELL: Good afternoon. I'm with the emerging fuels office and I'm here to talk about the natural gas price forecasts we're proposing to use for this session for IEPR 09.

The proposition before staff is to estimate what natural gas prices may be during the high and low cases that were discussed this morning. Because fundamentally, natural gas markets follow the petroleum market, so we need to be consistent with that through our price forecasts.

Now, the methodology I'll be describing applies for the feedstock costs used for compressed natural gas, liquid natural gas and even hydrogen feedstocks, okay. So this is a one-for-all approach in some cases.

Now, staff evaluated the crude oil and natural gas price relationships two different ways. One from the top down from the retail side, because we have a lot of data there; and from the bottom up from the commodity-based side.

So, looking at the commodity-based side, from the national scene, this graph illustrates the crude oil price and natural gas prices. And you can see they're fairly tightly linked in the past, with de-linking the most recently occurred in the last three years.

There's some strong market fundamental reasons why these two markets are closely linked, but we'll leave that for later discussion. Or we can discuss that later if people have questions.

But in California we see the same issues. We see the linkage between natural gas and crude oil follow closely to each other, with a possible exception of 2001 when there was a pipeline interruption, which was corrected. And then the markets then resumed back into market equilibrium.

If we take this phenomenon we were seeing in the markets and we apply that to our price forecast, I show this graph here to illustrate how we've done this.

This blue line on the far left is the historic natural gas procurement rates for the utilities in California. We've aligned them with the historic refinery acquisition costs for crude. And we've adjusted them so they align together with their energy values. And that's what the axis on the left and right axes do for us.

And so we take that historical relationship and then we apply that to the future price forecast. So when we have a high crude oil price forecast, say of $100 a barrel, we can estimate, well, the natural gas market will mostly likely be about $1.40 per therm.

And likewise, if crude oil is about, well, say $65 a barrel, we can see natural gas right about $1 a therm. This is the fundamental analysis that we use to estimate the feedstock costs for all three commodities going forward.

This is a table that's used on three different, CNG, LNG and hydrogen. So if you get familiar with one you'll be familiar with the other two.

This first row is commodity cost that we use as the -- which will vary each year in accordance with the low or high price cases. And this is compressed natural gas price calculation. And here we've added all the interstate tariffs, the compression costs, all the appropriate taxes that were currently used by Southern California Edison in 2009.

At the end of the day, at the bottom of the table, show you the gasoline gallon equivalent price in gasoline or diesel gallon units. And that was the bottom.

Now, if you look at the top down approach, which is looking at the retail end, we have from EIA the statewide average retail prices for the last ten years. And we also have, from the utilities, ten years of retail prices of PG&E and SoCalGas retail prices. And that's shown here.

For more purposeful uses we translate those to the differential costs, separating --

just subtracting the gasoline price from the CNG retail prices.

And you can see most of the time CNG is cheaper, lower cost than gasoline. Or lower cost than diesel. Those are the sole market differences between gasoline and diesel.

We carry these fundamental relationships over. And here on this table we show in the far-left column the retail prices. Now this retail price shows you for the last ten years at the pump what you would have seen is CNG would have cost 55 cents less than gasoline on a gasoline gallon basis. Or essentially 24 percent less. Likewise, diesel had a little bit lower cost, as well.

Now, for our forecasting purposes we carry this forward. We make the adjustments due to the federal excise tax, changes are done in October 2005. We add a retail margin to the utility fleets -- to the utility prices because utilities do not charge full retail margins like gasoline and diesel stations do. And we also add in a 8 percent sales tax.

So this far right-hand column is what staff is recommending as our starting point for the forecasts for the next 30-year forecast. So we would expect to see CNG retailed at 6 percent less than gasoline, and 7 percent more than diesel.

And here we combined the two methodologies, the top down, bottom up. And we can see one, fairly consistent, very close in their results. And staff is proposing that you use the upper one, this commodity-based approach, which has the most optimistic scenario for prices for the compressed natural gas, liquid natural gas and even hydrogen.

Now, all that discussion was at the retail end. And basically 90 percent of the natural gas used in California is used in heavy-duty fleets. And they typically don't pay retail prices.

So to make adjustments from the retail we're proposing that -- would take the retail prices just described, reduce them by 100 percent of this, these rack-to-retail margins that were discussed in the report that are applied to retail gas and diesel fuels.

And each has a different case for which case we're talking about. They have different numeric value.

Likewise, fleets that would be using diesel or gasoline would likely pay 50 percent of this retail price rack margin, because they would not be paying for the profits of the retail side, as well.

So this is the staff's position and we're looking forward to comments from industry to the appropriateness of these assumptions.

And then on to LNG. Same methodology. Taking the feedstock cost for natural gas. Varying that over time. And then applying the various costs to liquefy, store, retail, transport the LNG fuel. Get down to a final price of $1.82 a gallon in this example. And then you convert that to a diesel gallon equivalent basis and we see that there.

Now, in California LNG, LPG and compressed natural gas users can use a flat rate tax of 6 cents per gallon, or 7 cents a therm. And we're seeking comments from industry folks as to what's the most appropriate way to either pay the 6 cents per gallon, or to pay the flat tax, which is like $68 a car, or $168 for a truck. Most of the fleets, I believe, pay the flat rate tax.

And here's an illustration of what these translate to. And this is just on the gasoline side. So here's the high price of CNG in dark solid colors in blue. And the high gasoline price in the dashed line above it.

So you can see we're projecting on the gasoline side, at least, that compressed natural gas would be a lower cost.

And then likewise for LNG. We're showing the LNG here in solid line versus the high retail price of diesel in the dotted line, or the low dotted price here.

So in both cases, on LNG the lower cost per diesel gallon or gasoline gallon equivalent. And again, these, just like electricity prices, do not reflect the vehicle or efficiencies effects.

And with that I'll turn it over to Ryan to talk about the hydrogen price forecast, unless there's any questions at this point.

Anyone online with questions?

Okay, here's Ryan.

MR. EGGERS: Hello, again. My name's Ryan Eggers. I'm here to talk about the hydrogen price forecast, and then the propane price forecast. I'll be taking questions after each of the fuel types.

Hydrogen is the simplest element in the universe. Currently 95 percent of all U.S. hydrogen comes from the steam reforming process which strips away the carbon atom from the hydrogen atoms in the natural gas in order to get to pure hydrogen.

As Gary explained, again the base commodity for variation in these forecasts are our natural gas forecasts. And the same high and low natural gas forecasts were used here.

We did account for production, compression and transportation costs along with retail costs. All of these were accounted for and held constant in real terms throughout the forecast period.

As of this time there are no excise tax on hydrogen as a vehicle fuel. Therefore, the Energy Commission has only included in its estimates a base 8 percent sales tax.

Following the same methodology that was used in the LNG and CNG forecasts, this slide provides the actual calculation sheet in order to derive our costs. We'd like to note that the compression costs in this situation form roughly about 47 percent of the cost of the gasoline gallon equivalent final cost in the retail.

None of these percentages are held constant. Instead the actual values of the different compression, transportation and retail factors are the ones that are being held constant in real terms. Therefore, as natural gas price rises it becomes a larger percentage of the price.

Using this methodology these forecasts were then produced. The dotted lines below here are our gasoline prices going out to 2030. The solid lines are our hydrogen price forecasts. Since the natural gas forecast is tied to crude oil they again follow the same general patterns as we saw for our low and high price forecast.

We'd like to point out that these prices are in a gasoline gallon equivalent basis. And the actual fuel efficiency of the vehicle does need to be taken into account before determining what the true value of the fuel is.

At this time I'd like to take any questions regarding the hydrogen price forecasts. On the phones are there any questions?

MS. BROWN: Ryan, I have one question. Susan Brown.

MR. EGGERS: Yes.

MS. BROWN: How close is the transportation hydrogen fuel cost to stationary hydrogen produced by, day, you know, an Air Products or a --

MR. EGGERS: I think that had to do with the compression costs. I don't know what each of the different -- what's the necessary compression needed for the different types of fuels.

If I go back a slide here, --

MS. BROWN: So it's conceivable that a hydrogen stored in a higher pressure would cost more?

MR. EGGERS: That's basically where -- yeah, that's what's happening here. In the case of retail vehicle fuels, the required compression is about 3000 psi. And therefore, that's where a large amount of the cost is coming into the price forecasts.

Gary, do you have a comment?

MR. YOWELL: Yeah, if you look at that table, there's -- over-the-road delivery cost. That's 44 cents a gasoline gallon equivalent basis. And I would say that the average transfer costs for gasoline and diesel is probably around 8 cents to 12 cents a gallon, just for the average retail site in California.

And the higher cost is the tankage, but also it's a lower amount of fuel per tank carried. So that's consists of about three literature studies at this point.

MS. BROWN: But if it's stored in very high pressures -- could even have more volume in less space, right?

MR. YOWELL: You'll have more but you'll still have way less than gasoline or diesel would have been carried from the same truck, same -- yeah.

MS. BROWN: And hydrogen is a less energy --

MR. YOWELL: Very much less.

MS. BROWN: -- as fuel.

MR. YOWELL: Extremely less.

MS. BROWN: Right.

MR. YOWELL: That's why the high cost is there.

MR. EGGERS: Any other questions?

All right, I guess I'll move on to propane. Propane is a residual fuel created through the production of both crude oil and natural gas.

This said, previous EIA analysis of propane pricing indicates that it's most closely linked to the crude oil price. Mainly, again, the refiner acquisition cost.

Building on this foundation, Energy Commission transportation propane fuel price forecasts assume that the wholesale propane price is derived as a fixed proportion of the crude oil price.

In the high-price case forecast wholesale propane prices are 91 percent of refiner acquisition costs, which is the average percentage difference, or the average proportion, which is seen between 2000 and 2008.

The low-case wholesale propane forecast is 76 percent of refiner acquisition costs, which was the 2007 to 2008 average. The next slide really illustrates why we chose these two price points.

We then constructed a rack-to-retail margin.. In the case of the high price it was 64 cents. In the low case it was a 55 cents rack-to-retail margin.

We then included an excise tax, both

state and federal, and added it to the pretax price. And held that constant within real terms.

It should also be noted that excise taxes, there's two different ways to pay for excise taxes in the case of propane, just like in the CNG and LNG forecasts. It can be paid as a flat rate upfront. And we would like any advice on how to properly model that into our price forecasts.

A 8 percent California sales tax was also included into these forecasts.

As seen here, wholesale propane prices have roughly mimicked the refiner acquisition costs. Shown here in the blue line is the west coast propane wholesale price.

Unfortunately, there are no California-specific ones reported by the EIA.

The dotted red line is the refiner acquisition cost.

For most of this time roughly the same price. And from 2000 to 2008 again we get that 91 percent relationship with refiner acquisition costs.

But from about 2006 to 2008 a bit of a de-linking has occurred. Now, whether this is caused because of the price spike in crude oil, or from some other phenomenon, we can't quite say at this time.

But in order to model, if this becomes the new reality of the market, the 2007/2008 was used as the low cost, the proportion difference.

Also seen here are our west coast propane retail outlet price for transportation vehicles. Please note that the difference between this and the wholesale prices remain roughly constant and both of these lines seem to be moving at the same time within the same period. When one goes up, the other goes up. When one goes down, the other goes down, thus giving us our fixed constant margin.

Building on these assumptions leads to our forecast for propane transportation fuel into 2030. Again, this is tied to the refinery acquisition cost. And these prices roughly mimic those seen in the refiner acquisition cost forecasts.

This fuel, unlike the previous alternative fuels, is reported on a per-gallon basis. And, again, energy content and the fuel efficiency of the vehicle does need to be taken into effect when looking at these prices.

At this time I would like to take any questions regarding our propane price fuel forecasts.

Are there any questions online or on the phone?

I'd like to hand it back to Jim.

MR. PAGE: Just to review again. We will be finalizing these inputs to the demand forecast in the next few weeks, delivering our policy cases to the contractor.

We'll hold a second workshop in April on transportation energy infrastructure issues, both petroleum and alternative fuels. Preparing the demand forecasts and -- projections will be the subject of our next staff report. And we'll have a third workshop on that in June.

After which we'll finalize the report and integrate it into the IEPR, as needed.

And we'll be accepting written comments for ten days after this date.

But if people want to talk to us directly on any of these fuels, I've provided Energy Commission contacts, phone numbers and emails, and that would probably be preferable.

Thank you for participating, and, presenters, and thank you.

(Whereupon, at 1:50 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Staff 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 workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 20th day of February, 2009.

PETER PETTY