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

In the matter of,) Docket No. 11-IEP-1L

Preparation of the 2011 Integrated Energy Policy Report (2011 IEPR)

Volume II of II

Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report

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

Friday, September 9, 2011
9:06 A.M.

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Public Comment

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P R O C E E D I N G S

SEPTEMBER 9, 2011 1:22 P.M.

MS. STRECKER: Okay, everyone, welcome back. Our first speaker this afternoon is going to be Adam Langton, with the CPUC, and he's going to give an update to the electrical vehicle rulemaking.

And let me just add that we're a little bit behind schedule so if we can keep things moving this afternoon, that would be fabulous.

VICE CHAIRPERSON BOYD: I am now armed with a gavel and I can see the clock directly so --

(Laughter)

MR. LANGTON: All right, I'm going to go ahead and behind. My name is Adam Langton; I'm an analyst with the Energy Division at the California Public Utilities Commission.

And I work on -- excuse me -- I work on our electric vehicle proceeding. And I want to give a little background on our electric vehicle proceeding, talk a little bit about the adaption rate projects that we've received from the IOUs, and talk a little bit about some of the potential grid impacts and how we -- how we try to estimate what those will be.

So, the California Public Utilities Commission regulates the investor-owned utilities in California.

And in the electricity sector that mostly consists of PG&E, SCE and SDG&E. We don’t regulate the muni's, but what we do regulate comprises about 85 percent of electricity sales in the State of California.

In 2009 we started in electric vehicle -- or regulatory proceeding looking at electric vehicle adoption and how the Commission and the utilities could support electric vehicle adoption.

We essentially broke our proceeding into three phases. The first phase we looked at whether or not charging service providers and charging stations were categorized as public utilities or not, and that would determine how -- whether or not they would be regulation by the Commission.

Ultimately, we ruled that they were not under our jurisdiction and they are not public utilities.

And in our second phase, which we began this past spring or, rather, last fall and continued into the spring and issued a decision on in July, we looked at the utility role in electric vehicle adoption and electric vehicle charging. In particular, we looked at infrastructure issues, cost allocation and PEV tariff rates.

The decision did a number of things. I’m just going to go through just a couple of these in the interest of time. But this was -- our phase two decision was voted out in July of this year and this lists kind of the seven major aspects that we looked at in this decision.

A couple that I want to talk about right now are that we ruled that utilities are not allowed to own charging equipment that is on a customer premise. That falls on the customer side of the meter and so utilities are not allowed to own it.

And then number -- number two is regarding the shared costs of distribution upgrades. When someone installs an electric vehicle charging station, particularly in a residential area, it can have impacts on the distribution that is already set up in that residential neighborhood.

If upgrades are needed, that creates a cost that prior to this decision looked like it would be the responsibility of that residential customer.

What we decided is that we want to treat that as a shared cost until July of 2013. And the reason we want to do that is so we can have some time to better understand what those costs are and better understand ways to assign those costs.

So, we may reexamine that in 2013. We’ll have some additional information to do that by that time.

So, I mentioned that there's three phases. Phase three is begun now, and in phase three there are three issues that we're looking at. We are looking at load research and -- is the first one, let me talk about that.

So, as part of our decision we asked that the utilities develop a load research plan so that we can understand the impacts that electric vehicles have on the distribution infrastructure.

We felt like there was a lot of unanswered questions in this area and the way we would answer those questions is we would begin researching the electric vehicles that are out there and start understanding what their charging profile looks like, and try to understand how that impacts the distribution infrastructure that the utilities. And so that then we can start to understand how that impacts costs and then decide how we want to treat those costs.

So, they will begin that research in 2013 or, rather, they'll begin that research in the spring of 2012. And in January of 2013 they'll come to us with that research, we'll have that research to then start evaluating the PEV rates.

So in this decision that we passed, in July, we made some small adjustments to rates, but we realized we didn’t have enough information to make a lot of changes to those rates, so we want to do this load research so that then we can understand how to structure those rates.

One of the concerns is how do we minimize -- how do we use rates to write an incentive to discourage on-peak charging and encourage nighttime charging, so that’s one of the things we have to learn from this research.

There’s a lot of unknowns and we kind of have a sense of what those are. We’re not sure what the impacts that PEV charging will have on the electricity system. We’re not sure what the costs associated with off-peak charging are versus on-peak charging.

But we do think that there’s a big difference between the distribution impacts whether you’re charging on-peak or off-peak.

So, we know we want to encourage off-peak charging, but we want to get a sense of how people currently charge their vehicles, those early adapters that are purchasing their vehicles now and in 2012. And then understand how they’re charging them and then use that information to develop PEV -- to revise our PEV rates.

We’ve had PEV tariff rates on the books since the mid-nineties, when we first went through a round of PEV adoption. So those are still on the books, we're making some small adjustments to those this fall, but we want to really reexamine the structure of those rates after we have this load research.

The second area that we're looking at this fall is utility notification. To better understand the load impacts and what infrastructure upgrades are needed, we want utilities to be notified when somebody purchases an EV and installs charging infrastructure.

So, the utilities right now are working with different stakeholders to figure out a plan to get that notification. They're working with OEMs, and dealers, the DMV, and installers, perhaps local governments to figure out when -- who has access to information on when somebody is purchasing a vehicle and installing those charging infrastructure elements so that we can -- so that they can better anticipate where grid distribution upgrades will need to take place so that we can avoid outages and other problems associated with that.

And then the third aspect that we're looking at in phase three is sub-metering. So, we've ordered the utilities to develop rules that would accommodate customer-owned PEV sub-meters. And we've recognized that those sub-meters may be located on a house, they could be in a charging station, or they could be in the vehicle, itself.

And we'd like the utilities to develop rules to accommodate that so that they can use that sub-meter in their billing system and bill off of it. That would allow a customer to have a separate rate for their home from the rate that they charge for the -- from the tariff that they use for their electric vehicle.

There's a number of challenges associated with that so right now the utilities have formed a working group and they're starting to consider the different challenges.

And we've ordered them to send us a protocol of a set of requirements by July of 2012. So, they're working on that now and we want them to have tariffs submitted to us by September of 2012. So, a year from now we should have tariffs in place that will allow them to use sub-meters for billing purposes.

So, in terms of looking at EV adoption and an adoption rate, since I know that's the primary purpose here, at this particular workshop, in order to understand the grid impacts -- we want to understand both the adoption rates but, from a CPUC perspective, we're also concerned about what the charging behavior is and what charging level customers are using.

So this graphic here shows, in the lower left-hand corner, the rate of charge that we expect that customers could use. They could use a 120-volt, which is similar to, you know, a three-prong outlet that folks are used to using. It has a much slower charge rate and it takes a lot longer to charge up.

And these times indicate how long it takes to charge a vehicle from zero to a hundred percent full.

If we do see that folks are using the level two or the 240-volt chargers, and those are at 30 amps, then as this graphic shows here on the right, that charge level at the time that it's charging would exceed the average charge level for houses throughout different parts of California.

You can see a comparison to houses in -- households in San Francisco, Berkeley and San Ramon. It's significantly higher than that.

Since we're anticipating that most of the adoption, early adoption is going to take place in coastal cities, that comparison to Berkeley and San Francisco is pretty significant.

And that's important to us because if folks are using those high-level charges and the grid infrastructure is not built out to accommodate that, then we could see impacts like transformers degrading more quickly than we're used to or, perhaps, lower quality of electricity services to the homes in these areas. So that's why we're particularly concerned about this.

Now, the charge times there indicate the charging from zero to 100, which is kind of an extreme situation, and the 6.6 kilowatts that we see there in that graph assumes that somebody is using a level two charger. That's an assumption that we usually see in a lot of these estimates, but we don't know if folks are going to be using level two chargers or not, or what the penetration of level two chargers will end up being in residential homes. I'm going to talk a little bit more about that in a minute.

But next I wanted to talk about the PV adoption rates that we've received from the utilities. As part of our smart grid proceeding, we asked last fall that utilities develop smart grid deployment plans that outline their plans for deploying smart grid infrastructure.

And as part of those plans, which were submitted this summer to us, they provided PEV adoption estimates, and so we've received those as part of that proceeding.

We have not yet begun to analyze those. We just had the prehearing conference on this proceeding on

Wednesday, so this is still at an early phase of analyzing these things.

But I wanted to provide sort of what the estimates are that they provided to us and what kind of our early take on those estimates is.

So, first, this is SCE’s PV adoption rate. This shows cumulative PEVs in their service territory. They’ve provided a high forecast, a mid forecast and a low forecast.

The high forecast anticipates one million PEVs in 2020. And this appears to be a combination of BEVs and plug-in hybrid vehicles, and they also provide an estimate for 2015 as well.

And, again, these are three estimates and they include BEVs and plug-in hybrids.

PG&E provided a similar analysis, it looks very similar to what we see from SCE. In their high case, they’re anticipating 850,000 electric PEVs in their service territory in 2020.

And their low case in 2020 is only anticipating 220,000, so there’s a pretty big spread there between their estimates. And then the middle is anticipating about half a million PEVs in their service territory.

And then, finally, SDG&E also provided adoption estimates in their smart grid deployment plan. They provided one estimate but they broke out the plug-in hybrids from the all-battery electric vehicles in their estimates.

And as you can see here, they are assuming that the battery electric vehicles comprise about ten percent of the PEVs in their service territory.

And they're anticipating about 280,000 PEVs, altogether, in 2020.

In terms of the aggregate of these estimates, if we take the mid estimates from PG&E, and SCE, and combine that with SDG&E's estimate, well, we get a total of 1.2 million PEVs by 2020.

And if we want to look a little further down, kind of see how this looks from, you know, a density perspective, what this graph shows is the number of people per PEV in their service territory.

And you can see that the PG&E and the SCE estimates look pretty much similar, you know, comparing their low, to mid, to high. And so when you look at this graph, the higher columns indicate sort of a lower density, they indicate more people per PEV, and the lower columns are higher penetration rates.

So, the PG&E and SCE estimates look pretty similar when you compare them to a population basis.

SDG&E's estimate is lower than the PG&E and SCE high estimate, so they’re estimating about one EV per 11 people in their service territory. And that’s more -- a higher penetration rate than PG&E and SCE’s high adoption rates.

I’m not sure what to make of that, exactly. PG&E -- or SDG&E’s service territory is -- I’m imagining it’s more urban and it’s more coastal, and that’s where we’re expecting to see higher adoption rates, anyways.

So, looking at this, it’s hard to say whether that estimate is too ambitious or not, and it might be right on the mark.

But adoption rates are just one part of understanding the impact that EVs will have on the grid.

The other impact that we want to understand is charging behavior. And to give us a better sense of how charging behavior looks and how it might impact electricity needs, we put together a charging model at CPUC, and this is -- we’re in the process of developing this.

This is kind of the early stage, still at this point, so I want to show you some preliminary numbers. We’re going to complete this at the end of October and we’ll be able to share some final, some more finalized numbers from this.

But what we did was we took a DOT Transportation

Survey, where they surveyed households on their transportation behavior. They looked at when and where households traveled from and to, and how far they were traveling.

We took that information and looked at just the California information and tried to estimate how charging could look for a typical day for a customer.

This is just a one-day snapshot of drivers that they do in their transportation survey, so it’s a little bit limited in terms of what it says.

But we took this analysis and the first thing we did was we tried to figure out what the average driving range would be for drivers. The different averages are there, at the bottom of this table, based on different cuts of the data that we took.

But it’s about between the mid-thirties and high thirties in terms of average miles per day that customers are traveling.

The chart here breaks those down, breaks those vehicles down into different groups. The largest one, of 43 percent, is driver who travel zero to 20 miles per day. Those drivers would need less than five kilowatt hours per day to charge.

Now, they only need five kilowatt hours per day. If they have a charging station that charges at 6.6

kilowatts, they would be able to charge in less than an hour.

So, what this could suggest is that there are customers who don’t need a level two charging and may be able to do all their charging with a level one charger. If that’s the case, the grid impacts look a lot different.

So, from looking at this data we are curious as to how many customers will actually adopt level two charging stations and wondering if we’ll see more customers that are adopting just level one charging stations since they have small driving ranges.

But, obviously, there’s some drivers that -- you know, about 15 percent or so that are driving more than 60 miles per day, they would certainly need a level two charging. But it’s questionable as to whether drivers that are driving that far would want to buy an electric vehicle in the first place.

Infrastructure, in that case, could provide -- public infrastructure and workplace infrastructure could provide an incentive for them to do that charging.

And then what we did was we took this data and we broke it down, and we looked at charging throughout the day. Since we knew where cars were throughout the day, we wanted to look at what charging could look like at different times of the day.

And this is kind of an extreme scenario, we assume that level two charging stations were available at every location, wherever anyone parked. This is kind of unrealistic but it kind of provides like kind of a bookend to some of our assumptions here.

Based on this assumption about 98 percent of drivers could complete all their driving needs, if they had all those charging stations. Two percent couldn’t because they were simply driving too much or driving too long before they came to a charging station.

We looked particularly at peak charging, that’s that red-highlighted area, and what we found -- so this is looking at average kilowatt hours or kilowatts per vehicle. And what we found is that using our data during the peak hours, assuming the peak hours are 11:00 to 6:00 p.m., there was about 3.2 kilowatt hours per vehicle.

And what we saw here, under these assumptions, is that the peak charging is happening during these peak hours. Not much charging is taking place at night. In fact, the average battery is 97 percent full at midnight, under these assumptions.

If we assume that drivers are only using level one charging, that’s what this scenario shows, that we’ve put level one charging, which are essentially three-prong outlets, at every location where someone parks. And you can kind of see the comparison here between level two and level one.

Peak charging drops to 2.8 kilowatt hours per vehicle but, at the same time, we’ve moved from a lot slower charging but, still, 95 percent of drivers can complete their driving needs.

And batteries are still 91 -- the average battery is 91 percent full at midnight.

So under -- using just level one charging, folks are able to complete a lot of their charging.

One of the concerns that we have with this data, that we’re going to look at revising, so we’re concerned that this data may over-sample nonworking households.

In DOT’s dataset they did have a weighting factor that’s designed to account for that and we used that weighting factor in this data, but we’re a little bit concerned that the charging rates that we see between 1:00 and 5:00 p.m. seem a little bit high to us at this time. So, we’re looking at ways to adjust the data to account for that.

But based on this data we are -- we are curious to see what the adoption rate of level two charging stations will be.

The common assumption that we see is that all households will adopt level two charging stations, but we think that the data suggests that there may be a lot of households or certain kinds of households that will not use those.

And this is important to understand and something that we hope to learn through our load research because it has a big impact on the grid infrastructure impacts. And when we understand that and when we take it and combine it with the adoption rates we can start to understand what kind of infrastructure impacts, what kind of infrastructure costs we'll be facing.

And we can use that, we can also use that information to understand how to structure our electric vehicle tariffs.

At this time I'd be happy to take any questions.

VICE CHAIRPERSON BOYD: Thank you, Sam. Real quickly and I don't know if it's a question to you, or to everybody in the electric vehicle area. And I meant to say, before introducing you, that to those in the electric vehicle area who felt neglected this morning, I noticed in the agenda I was giving of who's testifying that this entire section is electric vehicles, so you're getting more than your fair share of the agenda.

That aside, you had vehicle estimates, the ARB does vehicle estimates, we do vehicle estimates, the PEV collaborative which is fairly new and we'll hear from them shortly, does vehicle estimates. I have no idea if these are all in concert or whether we have differences.

So, I just throw that on the table. I don't expect you to know the answer, unless you happen to know the answer, because you folks are part of the PEV collaborative as well.

MR. LANGTON: Yeah, I'm not sure to what extent collaboration is occurring on these estimates. We know that the utilities are involved in the PEV collaborative, and there's other collaborative groups that are working together.

But I think that's a good question as to how we can coordinate these.

And this is -- they're just looking at their individual service territories. And I know some other groups are looking at statewide estimates, which would then include Sacramento and L.A.

VICE CHAIRPERSON BOYD: Okay and here comes the PEV collaborative.

MR. CUNNINGHAM: Joshua Cunningham, Plug-In Electric Vehicle Collaborative. And I'll just say that I have two slides teed up in my slide deck to address that question.

VICE CHAIRPERSON BOYD: Good. Thank you.

Okay, next we're going to hear from the utilities, I guess, and Alex Kim, SDG&E, also a member of the collaborative.

MS. STRECKER: I think Commissioner Boyd just did a wonderful job of introducing you. Now, I don't have to. Thank you.

VICE CHAIRPERSON BOYD: I'm using the fast gavel, fastest approach to the afternoon approach.

MR. KIM: Good afternoon, Commissioners, thank you for inviting me to participate. I'm more than thankful to be here after what's happened in San Diego, yesterday.

VICE CHAIRPERSON BOYD: Glad you got out.

MR. KIM: I'm glad to say that all of our 1.4 million customers got their service back in 12 hours, so it's a tremendous job, very proud of our company for getting all of our customers back online.

VICE CHAIRPERSON BOYD: It wasn't one of your workers who made the mistake.

MR. KIM: And it wasn't our fault so --

(Laughter)

VICE CHAIRPERSON BOYD: But it really has brought into question, in this Agency, why the simple act, theoretically, of pulling a monitoring instrument out shuts down a big part of the Western United States.

MR. KIM: Yes.

VICE CHAIRPERSON BOYD: Well, anyway, you'll all look into that, I'm sure.

MR. KIM: I'm sure there will be much more to say about that as well, too. But thank you, again, for the opportunity.

I'm going to focus my discussion primarily on giving you a little bit of insight on what's happening in San Diego with the plug-in electric vehicles.

And I'm also going to focus on some of the barriers and offer up some, at least, solutions from our perspective for electric vehicles, and how do we get rid of those barriers with electric vehicles.

So, we just talked about -- a little bit about the projects and so this is the projections of many different organizations, some from a very high rate projection, some a very low level projection.

This particular chart here is from the California Plug-In Electric Vehicle Collaborative, where you see a lot of different estimates. And you just saw the differences in the utilities with our projections, with the plug-in electric vehicles.

And the variations are very much in the line with what Adam is saying. One of the things, for example, with San Diego and why our projections are so high, and I’m going to talk a little bit about it, is because of the activity that’s actually happening in San Diego and the type of customers that we have in San Diego we believe warrants a much higher projection.

But is that projection right? You know, we don’t know. We think it is definitely our best estimate based upon the information that we have and based upon, you know, the adoption of hybrid electric vehicles, for example, in our service territory and the very high-tech community that we do have now.

So, just a little bit about SDG&E’s situation; our area is part of the EV Project, which is a project that is a DOE-funded project to install electric vehicle charging infrastructure throughout the United States.

In the San Diego Region that includes 1,500 public charging stations, as well as 1,000 home charging units.

We also have some additional funding from the CEC, thank you, also for that, to install chargers in that project as well, too.

In addition to that, one of the things that we are doing is we’re also doing a rate experiment, and so one of the things that we’re testing is the price elasticity of customers and their behavior to charge during the off peak and during the peak period, and understanding -- providing that price differential and what price differential makes a difference for them to charge in different periods. And we’re just starting to get some of that data in, now, and I’ll share a little bit about that a little bit later.

Another thing that’s happening in San Diego is Car To Go, which is an affiliate of Daimler. Had announced its first all-electric car sharing program to be launched in San Diego, this will be the first in the world.

They’re going to have 500 Smart EVs as part of this program. These vehicles will float throughout the San Diego Metropolitan area and they’re going to be starting that program in December of 2011.

Lastly, there’s been several announcements from different auto manufacturers planning to launch their vehicles in California but, specifically, in San Diego. So, again, one of the reasons why we have a higher projection rate than maybe some of the other utilities in California is because of the different discussions that we’ve had, and the different announcements that we’ve seen as far as electric vehicles coming to the San Diego area.

This map here shows currently, at least as of June, the number of electric vehicles that we have throughout our service territory. We’ve mapped this by transformer, so the green dots that you see there are actually number of electric vehicles, one electric vehicle per transformer, or one customer per transformer.

The yellow dots that you see there are two customers per transformer.

And the most interesting one that you see there is the blue dots, which is customers that have both electric vehicles, as well as solar photovoltaics.

Currently, about -- just some statistics, we have about 500 Leafs, at least that we know of, Nissan Leafs in our service territory.

We’ve got over 100 Chevy Volts in our service territory, so over 600 electric vehicles so far in our service territory. And this primarily had started probably early in Q2 is when the bulk of the vehicles were starting to arrive this year.

About 47 percent of the EV owners have a higher income base, as well. And the electric vehicle owners that I mentioned, that also have solar, about 35 percent of them also have solar.

We’re also seeing about an average charge rate of about 7 to 8 kilowatt hours per customers in average use per day, so that equals about a 25-mile range on a Nissan Leaf as well, too.

So, going back to, I think some of the information that Adam presented, we’re also starting to see, you know, customers not necessarily needing to have a full charge on their vehicles. At least in our service territory where we -- our metro area’s relatively close, so in our area we don’t see that -- we’re not starting to see that need as much with our customers.

Talk a little bit about some of the barriers and solutions, and so I’ve got four -- four areas I really want to focus on and one of them is the fuel price.

As was mentioned earlier today, the fuel price with electric vehicles, we believe providing that incentive to our customers, helping them to drive down the cost of that fuel, in other words the electric prices, will help drive electric vehicle sales.

And one way to do that, I know the discussion after this is going to talk about the low-carbon fuel standard. One way to do that is to take the credits and the value of those credits that are generated and provide those as an incentive to help drive down the costs.

So, that accomplishes two things. One of them is it helps customers and consumers to continue to have that price signal, to be able to purchase electric vehicles. But secondly, and I think most importantly is it provides that experience, that continued experience so when they're buying their next electric vehicle they'd still have that price signal and that continued motivation to want to drive the electric vehicle.

Just an anecdotal note here is, you know, we've had customers that, initially, when they purchased their electric vehicles they did it because they wanted to be green, they wanted to have something new, they wanted to have the new technology, but it wasn't until they got their first electric bill that they realized what a significant savings that it was and what a tremendous investment it actually was for them as well, too.

And we think that word of mouth, as that starts to spread to their friends and family, and through the different electronic mediums, we're starting to see much more customers very interested in electric vehicles.

And so while we had a very high projection for plug-in electric vehicles or plug-in electric hybrid vehicles versus battery-electric vehicles, you know, we may start to see actually more electric vehicles and plug-in electric vehicles than we originally had thought.

The other thing is these incentives can also be used to help to drive -- to control the rate of charge. And so, example, with our demand response programs we can provide that incentive from the credits that are generated to our customers as well, too, to further encourage them to help the grid, which would have been very helpful yesterday, and actually today as well, too, in our service territory. But also help to control the rate of charge, but also the timing at which our customers charge.

Here is some data, this is very early data that we’ve collected from our customers here. Here, you see about 86 percent of our customers are charging during the super off peak. For SDG&E that period is between midnight to 5:00 a.m. About nine percent of those customers are charging during the off peak. And only five percent are charging during the on peak.

Again, this is at home, so we don’t have the data yet for what’s happening with public charging. But at home, primarily, most of the customers are charging either during the off peak or during the super off-peak period.

Also what we have included here is the price of our -- or at least our equivalent price of gasoline as well, too. So, in the on-peak period when our rates are around 38 cents for our high rate that we're testing, the equivalent gallon is about $2.74 cents. In the off peak it's anywhere from 54 cents to 99 cents.

So, I know there's some discussion about the chart in the report and so, you know, we'd be glad to work with staff as well to understand where those numbers came from, and provide some of the estimates that we have as well.

Barrier number two is the price of ownership for the electric vehicles so, one of the things that we see as a solution is maintaining the current incentives that are available, now. We need to ensure that the cost of the vehicles are still affordable. We think that's needed at least until the market is established.

So, maintaining both the Federal and the State incentives are important. It encourages the customers to buy the electric vehicles now, it gives them that incentive to act. But it also helps to encourage more growth of the industry, specifically in California, and driving more jobs into California for the services that are needed to support those electric vehicles.

Barrier number three is the consumer and stakeholder knowledge. Right now that is very minimal. The utilities are doing a tremendous effort, I think, in all their service territories, both the municipal utilities, as well as the investor-owned utilities at providing neutral and informative information, such as information about rates.

So, not necessarily providing information about the vehicles, themselves, we believe that’s the responsibility of the auto manufacturers and the dealers.

But encouraging customers and making them understand about, you know, when is the best time to charge, what is the value of charging during those different periods of time?

But not only doing outreach for our customers, we’re also talking about the different markets within our customers. So, for example, the multi-unit dwelling area, apartments and condominiums, for example, they have different types of needs working with the homeowner’s associations.

So, for example, one of the things that we’re doing at SDG&E is we have workshops, where we invite the homeowner’s associations to there, we invite the contractors, as well as the EVSE installers to talk over the issues, and for them to be educated on what it takes to provide charging in multi-unit dwellings.

The same goes for fleet and workplace charging.

One of the things that we’ve done as a company, and we’re pushing this information out to our customers is, as a company we’re offering workplace charging.

But as a corporation, we understand that there are different issues, tax-related issues for example, issues related to policy about when employees can charge, and how long they can park there.

So, we’re taking that information and we’re sharing it with others, we’re sharing it with the California PEV Collaborative so that information can get passed out to the different commercial customers that we have, as well as providing information about fleet charging.

Lastly is the stakeholders; the policymakers, the dealers, for example, are a key, critical piece to this, making sure the dealers understand the information.

We talked a little bit about -- it was mentioned a little bit earlier about having the OEMs and making sure that the customers contact the utilities before they purchase an electric vehicle because it’s not like buying a regular vehicle, where you can just drive the vehicle off the fleet, go to your nearest gas station, fill it up and go.

It takes some time, for example, to coordinate.

If you are getting level two charging, to get a charging station you have to have a contractor come out there and install that, and when to charge your vehicle.

So, those are the types of education that we want to make sure that the dealers understand, that the customers need to contact the utilities as well, too.

Last barrier is the cost of the electric vehicle service equipment. So we talked about or it was mentioned earlier that the cost of this equipment right now is relatively high. And so we believe that one of the things that needs to be done is to encourage a lot of different options.

And so Adam talked about different ways in which a customer's going to charge. Are they going to charge using level one charging, level two charging or even possibly, you know, have the need to have -- to do DC fast charging for public charging stations.

And we think there's a lot of different options that need to be available out there. There are definitely a lot of companies out there that are offering this. We're well aware of over 40 companies right now that have a different product. And so creating that price and product competition is very important.

And also providing incentives, I believe. Right now the Federal -- the Federal government has an incentive for these. We believe that needs to continue until the cost of these go down.

But also it depends on the different types of technology options that are needed for these electric vehicle service equipment. Some of them can be very basic. If you've ever looked inside one of these, it's just a few wires put together and some of them are very basic, where other of them are very sophisticated. They have smart grid technology capability, for example, they can interface with the meter, but those add cost to the equipment.

And so letting the utilities, I think, work with the electric vehicle manufacturers or electric vehicle service providers to determine what service, what technology options are needed to provide the lowest cost.

The last slide I have here is just a glimpse into the future. So I started off talking about, you know, what is the projection of electric vehicles in the future?

And this was an event that was a dedication for the first public charging station in Balboa Park, which is a big park in San Diego. What you see there is over 60 electric vehicles in the parking lot, probably the largest gathering of electric vehicles in the country at this time.

And this was a few months ago. And the question is, you know, is this what our future's going to be? Is the future going to be electric vehicles? Is this what the parking lot of the future is going to look like, where you've got a lot of electric vehicles in one location?

I don't have the answer to that. I wish I did have the answer to that. But it's definitely a future that the utilities are working toward. Trying to break down some of those barriers I mentioned to you are the activities that we're working toward to help make this future happen.

So with that, thank you, and I'll take any questions.

VICE CHAIRPERSON BOYD: Thank you. Any quick questions? Seeing none, I'll thank you.

MR. KIM: Thank you.

MS. STRECKER: Here comes Adam to make a comment. And then after Adam, Joshua Cunningham, from the PEV Collaborative, will speak next.

MR. LANGTON: One thing that I wanted to mention, that I had forgotten to mention, that now Kyle reminded me of, is regarding the LCF credits and how we’re addressing those credits that go to the utility.

We have a GHG OIR that is looking at the use of GHG auction revenue that goes to the utilities that began this summer. As part of that we’re also looking at the use of LCFS revenue that goes to the utility.

And we’ll begin looking at that revenue, the use of that revenue, in January. We’re anticipating that ARB will have a new LCFS ruling in December and once we have that we can start looking at the use of that revenue.

So, that was the one thing I had forgotten to mention that I wanted to put out there.

MR. CUNNINGHAM: Thank you for the opportunity to present, Commissioners and staff.

There are a number of areas that the Plug-In Electric Vehicle Collaborative operates in but I want to focus today a couple of trends and observations we have on the infrastructure topic, given that that’s the most relevant issue for your workshop today.

As a multi-stakeholder collaborative, with the Air Board, and other agencies, and private sectors, we’re very happy to have CEC and direct engagement of Commissioners and staff in our program. So, thank you for your participation.

There are three key topics I want to hit on in my brief slide deck. The first is what I’m calling kind of the today’s numbers, some vehicle count and charging counts that we’re seeing this year and next year, to give some context.

I’ll also have a couple of slides, as I mentioned, on the projections, on the current projections out there.

The second topic is the -- a few areas within the Collaborative activities that we’re touching on related to charging infrastructure, and then some interesting trends that are emerging that should be quite relevant for the longer term in terms of cost reductions and public infrastructure growth.

So, everybody’s familiar with the Leaf, the Nissan Leaf, and the General Motors’ Volt, both of those are on this table. But I want to highlight that every major manufacturer has a product coming to market that’s a plug-in vehicle in the next year or two.

The one that’s next coming up is likely the Ford Focus, which is in the lower left there, coming out late this year. BMW, the car right above that, is also coming out, and then Honda, and Mitsubishi. So, everybody has a car coming out.

And I think it’s pretty clear from what we’ve seen in the press that there are long -- there are waiting lists for the Leaf and the Volt, so we don't expect a demand issue from the next year or two in the early adopters.

The critical issue is can we sustain that demand, both as we move past early adopters and as we move into a saturation in the market with a larger number of auto companies bringing products to the market.

So those are large unknowns. All we know today is that we have two exciting cars on the market and they're selling well.

So, I have two slides on the projections. This one Alex presented earlier, it was from our Taking Charge Report in the fall. And it's meant to be only a comparative slide of all -- a large number of the projection studies out there.

So this is 2020 sales projections from a number of studies. And to give some context, the way we look at this there are two types of projections. One are organizations that have policy targets in the future and they're looking backwards to try and project what are the required number of electric cars to meet certain targets, whether it be a 2050 GHG target or some other metric.

And then there are forward-looking projections that take into consideration traditional factors of vehicle price, technology readiness, consumer preferences, et cetera.

And, commonly, they'll arrive at very different answers.

So, I just wanted to provide this as a scale of what's being discussed.

Category Item C is the Air Resources Board's public statement they've given in terms of what will likely be coming out in the ZEV regulation proposal to the Board this fall.

It's around five percent by 2020, the regulation will be going out further than that.

But then you can see there are a number of studies that go up to a higher projects.

And I think the easy answer, Commissioner Boyd, is that nobody knows exactly what's going to happen and I certainly don't have a crystal ball.

But I do think that in terms of policy and fuels analysis in terms of what the Energy Commission has done, using the State's zero emission vehicle regulation as a touch point for sales, I support that approach to ensure consistency in what we're looking at.

COMMISSIONER PETERMAN: Excuse me, Josh, you mentioned that there's two types of approaches. Can you highlight which of these took which approach, versus focusing on the mandates and working backwards to building up?

MR. CUNNINGHAM: Yeah, two examples of the looking backwards from a policy target, Item C, which is the Air Resources Board’s projections. The new proposal that they’re taking to the Board takes serious consideration into the 2050 greenhouse gas target, the Governor’s Executive Order. So, that was a looking backwards approach.

The last one, which has a much higher projection, the International Energy Agency did the same thing. They looked at the United Nations’ 2050 targets and what it meant for the North America Region and that was their number.

Looking forward, a good example would be the McKinsey Study, Item G, or the Boston Consulting Group, Item H. And so there’s -- but even within those groupings there’s variations, so it comes down to assumptions.

I’ll mention for context that it took ten years to get the hybrid electric vehicle market in California to five percent. The conditions for the electric vehicle market are different, I’ll acknowledge that, but that’s an important thing to keep in mind that in terms of on-road fleet growth it does take time to develop market penetration.

So in California, today, we’re at about five percent of new car sales are hybrids, and so that’s ten years from the early sales.

So going back, this is the chart we had in the Taking Charge Report. We are purposely not picking a specific projection as the Collaborative. The Collaborative’s effort is to simply try and advance the market and deal with challenges. We’re not going to try and venture into the debate of which number is right. But we showed this to show the range.

So the lower slice, the green slice are sales, and the band of that correlates to the previous slide of the different scenarios are out there.

The State’s ZEV regulation is closer to the bottom part of that slice.

And then the blue slice would be the on-road fleet numbers. And so for a range, in the green area this represents in 2020 on the area of hundreds of thousands of sales per year in California, equating to on the road of between a half and one million PEVs on the road, so there’s a wide range there and most of them are relatively aggressive.

For specific sales this year I threw the boxes on the top. As of July, there were 3,000 Volts sold in the country and over 4,000 Leafs. The Leafs are now up to about 6,000. GM has disclosed that about a thousand of those are in California. And Nissan hasn’t said, but it’s safe to say maybe half of those are happening in California from what we’ve seen from the utility numbers.

Some relatively reliable projections could say at the end of this year we’ll get about 15,000 sales in California, combined Volts and Leafs, so that’s just some context.

For stations, the Energy Commission knows a lot about this with your AB 118 program and public charger investments.

The slide here on the left is from some of the Energy Commission’s work on the existing stations pre-2011. A lot of these are due to be upgraded to the new standards for the SAE plug.

But in the text language I just wanted to provide some rough numbers that we’re talking about, between five and ten thousand public chargers going in, in the next year or two, in California, which is significant. And so the challenge is how do we plan appropriate for where those chargers should go and how do we learn from how well they’re being used.

And I'll mention that within those numbers there's a very small, but important, quantity of DC fast charging that are going into a couple of Bay Area and Southern California. And then there is one better place, battery switch project happening in the Bay Area. So those will provide some lessons in terms of how often are they used, how do they impact the grid locally, and what are their costs, et cetera, so those will be important to study.

So, briefly, what we're doing to address -- you know, our goal as a multi-stakeholder effort is to identify what are the key challenges occurring over the next ten years that we expect to be needed to tackle to move the market forward? And where is there a need for partnership between different stakeholders, what can we do collectively?

So one of the areas, we've broken down the phases over the next ten years into kind of a market launch, market growth, market takeoff in terms of the potential scale of sales.

And in the early stages the demand for the cars are not the challenge, the issue in the next year or two, on the ground today is how do we streamline the residential equipment upgrade and getting owners their equipment installed in an efficient way?

And then, also, when we're looking at the public planning for the public stations how do we -- what are the rules of thumb that we're learning about where public charging should go and how do we deal with local bottlenecks?

So, Malachi did ask me to elaborate a bit on the streamlining of the charging issue. There's a large number of stakeholders in California dealing with this, utilities are directly getting involved with their homeowners, the auto companies are getting involved.

And broadly what it involves are two areas; one is process. How do we make sure that the local cities, that each city that has EVs coming into their residence has a system for permitting, and inspection, and getting the equipment put in place in a timely fashion.

So there's definitely process issues that involve local contractors, inspectors, and front desk people of the city staff.

The other issue is once you get past the process there are -- how do you get the correct decisions to be happening between the homeowner and the utility?

So once a homeowner buys the car there's a number of decisions that the utility companies and the State, when we deal with grid impacts, want the homeowners to consider and that has to do with level one or level two, which is a 120 versus 240 charging equipment. It also has to do with time-of-use rates. Is the homeowner going to be educated and understand what their options are for that?

Another tier there would be if they take advantage of a second meter in the home, they could get a special EV time-of-use rate. And so there are a number of issues there, all of which have cost implications.

And so part of the streamlining issue is how do you -- what's the robust process for all those homeowners to get that information and make those decisions so that we can grow the infrastructure

And one trend that I'll highlight later on, that Adam brought up, is that some of the hybrid owners likely won't need a level two in their garage, and so we want to make sure that they know that before making investments. And that depends on the size of their battery in their car and their commute patterns.

Just briefly and kind of looking at the next phase, past early adopters, depending on how the market grows, vehicle cost reductions will continue to be likely the biggest issue.

But moving into, again in the residential charging equipment side, we all need to start moving forward on what is the protocol and arrangement for sub-meters in their garage, so homeowners can take advantage of the special TOU rates for the EVs.

That will also likely be an issue when it comes to policy, like the low carbon fuel standard or fuel taxation changes in the future.

And then there is some technology evolution where we'll have smart level one chargers, so an extension cord that has some smarts to it, that can do demand response, talking to the utilities, and be a much cheaper option than some of the equipment that's being putting in there today.

And the workplace charging needs to be the next front that we put focus on.

And then, finally, long term continued reductions in the cost of the vehicle and the battery, but there will be some new factors in the equation in the future, and we're not sure when that happens, but there will be new things that affects the cost tradeoffs that the consumer thinks about. There's going to be changes to the national fuel taxation so that EVs and hydrogen cars don't get a free ride anymore.

There will be potential value from the low carbon fuel standard passed down to the owners. There will be potential V2G issues in the future, battery second ownership. A lot of these are speculative so I'm not going to put any validity to it, but only to say that there will be some things in the future that will change the equation of the car and the ownership.

I won't go through this, but you'll have it in the slide deck. These are the five broad areas that we have set up working groups to tackle. But I want to just focus on the infrastructure today and stick to my time slot.

On the infrastructure topic, in coordination with local communities, one of the early actions that we took as a collaborative was to bring a number of our partners together and put together a single statewide proposal to the Federal DOE grant solicitation that came out in the spring.

They had identified $5 million for the whole country. And differently than the ecotality of the cool-on earmark money from the Feds a couple years ago, this is money that DOE's putting into, specifically for -- it's not for equipment, it's for local planning efforts, to get money into the hands of local planners to improve how they install public and private charging.

This is very similar to what the Energy Commission is doing with the chunk of -- their $1 million from the AB 118 program, and we've been coordinating with them on that.

We asked for $1 million for the State and we helped to organize the State into six broad regions, where we had a leading stakeholder and set of partners somewhat roaming around the DOE clean cities stakeholders in each region.

And the goal is to make sure that we're coordinating between the regions, that we're establishing workshops to do training for local policymakers, et cetera.

And I'll just, in closing, that a very timely announcement, yesterday we heard we got this award, so we're very excited about that.

Finally, two or three slides on some interesting trends that might play into how the Energy Commission and other stakeholders think about planning for infrastructure. These are just observations on some of the many announcements and private sector activities that are occurring that I thought were interesting.

On the OEM front Ford, and a couple of the other companies, are starting to connect outreach issues for the renewable power for the car to their buyers. So, Ford has a partnership with SunPower to make sure that the dealership car owners are becoming aware of what they can do in their home for renewable power.

It’s not getting in the way of PVs or anything else, but it’s just connecting stakeholders to each other and information to pass all along.

GM, and a number of other companies, are experimenting with direct communication with the utilities, so demand response capability of tying the utilities to the cards.

Nissan, and this is an interesting one, after the nuclear disaster this spring, they’ve already had several of the car companies with conventional hybrids having 120 plugs doing vehicle-to-home capabilities to provide backup power.

And Nissan now has announced their going to take a V2H capability for their leaf in Japan. They’re not doing it in other markets, yet, but that’s an emergence of what happened this spring and potentially something that Japan’s going to jump on.

And then the only other one I’ll mention here, Nissan and City Ventures, that’s an example of some of developers getting involved in doing EV circuitry designed into new homes, so all their homes in that particular development would have a 220 circuit designed in from the get go.

On the charging partnership side, just some trends to note. Most of the auto companies have partners on this. But Leviton, which is one of the largest and, you know, oldest companies doing electrical equipment, is now partnered with Ford, Mitsubishi and Toyota to do their equipment for their electric cars. So, that’s an important partnership of some large companies with established history.

Best Buy is going to be a contractor to help distribute some of that.

And then the third one I’ll mention there is that GE is getting involved with their equipment and they’re going to be distributing it through Lowe’s.

So, I think I just want to point out that there are a number of large, traditional retail outlets and partners that are getting into this, that should bring some investment capability and confidence to the consumers.

And I’ll close on this one, to just summarize a couple of the trends on the infrastructure side. The triangle down at the bottom, a lot of the stakeholders point to this as out of all the charging that the EV owners are going to want to have access to, the experts believe and we hope that it goes this direction, the majority of charging happens at home, because that can primarily be nighttime off peak.

The next level of demand would be from the workplace charging and then, finally, the small chunk -- hopefully, small chunk would be public.

And so the question of how big these pieces of the pyramid are is a big issue, but I think most people see this as the appropriate balance.

In terms of the residential -- the cost ratios of the residential equipment, because that will be a hindrance for the market, smart level one, cord sets as I mentioned, which would be a 120 circuit capable of doing communications with the utilities, vehicle communications with the utilities and then the sub-meters. These are all topics that are really important.

And then just an observation, plug-in hybrids likely will rely on public infrastructure more than battery electrics. Battery electric cars would be able to have a longer electric range and could charge at home.

That’s not, you know, a blanket statement, but could be a trend that’s important to monitor in terms of which of those two technologies are more dominant in the fleet.

And then just to mention that the multi-unit dwelling topic is going to become an increasingly large challenge that we need to tackle.

So, let me stop there and I’m happy to take any questions.

VICE CHAIRPERSON BOYD: Thanks Josh. Any questions? WSPA? Time's up.

(Laughter)

MS. GREY: Gave me enough time to get the mouthpiece down to me here. Gina Grey with WSPA. Slide 9, when you talk about addressing market challenges, the last bullet, you have long-term market takeoff 2020 and beyond, and the last bullet there says "no cost factors LCFS."

So, are we to infer from this that the Collaborative feels that, really, the LCFS credits in terms of impact probably wouldn't be kicking in until the 2020 and beyond time period?

MR. CUNNINGHAM: I'm going to avoid that question somewhat, only to say that to begin with the Collaborative, we're not going to be taking positions on policy. So we're not putting out opinions on what's going to happen on the regulatory side.

And so the use of the 2020 there was supposed to be a little bit vague.

But from my personal expectation, I would think that it is later in the decade that we'll start seeing electric LCFS credits having the value in the market, but that's strictly a speculation.

MS. GREY: Okay, which -- thank you. Which would be a concern, obviously, because ARB is considering those credits being available before the end of the 2020 time period within the LCFS program.

MR. CUNNINGHAM: Yeah.

MS. GREY: And I guess there are a lot of utilities that are a part of your Collaborative. Have any of them expressed, because I did ask this question during the last workshop we had for this subject, asking them whether they anticipate having an ability to purchase credits from the oil industry, et cetera, and none of the utilities at that point in time had anything to say.

So I was just wondering if, during the Collaborative discussions, if that has been discussed?

MR. CUNNINGHAM: No, we have taken a pretty clear approach at the Collaborative that we do not want to venture into specific regulatory discussions.

MS. GREY: Okay.

MR. CUNNINGHAM: And that's to make sure that the individual stakeholders feel comfortable in our forum that we're talking about public issues that are common challenges.

MS. GREY: Okay.

MR. CUNNINGHAM: And so we're -- we won't tackle that directly.

MS. GREY: Thank you.

VICE CHAIRPERSON BOYD: Seeing no other hands or people leaping up, thank you Josh.

MR. CUNNINGHAM: You bet.

VICE CHAIRPERSON BOYD: Gordon, it says here you're going to talk about renewable fuel standard, now.

MS. STRECKER: Before we have Gordon, we're going to have a couple minutes from Tim Carmichael, I understand, and then Gordon will be up.

VICE CHAIRPERSON BOYD: Uh-oh. You want equal time?

MR. CARMICHAEL: No, the EV and plug-in hybrid folks are a lot more long-winded than I am.

(Laughter)

MR. CARMICHAEL: That was a joke. I love you guys, that was a joke.

Just thank you to the staff. Just a few brief comments and I'm doing it now because it fits in better following up on what the staff has already presented this morning. And I will share these bullets with the staff, I just didn't get them into a presentation in time for right now.

Just a broad point, there's still quite a bit of contrast between where the IEPR is and where the AB 118 investment plan is. And what I mean by that is even the background information that's put into the two plans in some cases almost seems in contrast, or contradictory, as opposed to on the same path.

The AB 118 investment plan, the one just adopted is talking about demo projects of hundreds of natural gas trucks in the, you know, heavy-duty market, large quantities.

The IEPR is, at least based on the data so far, is more focused on projections based on transit and what might be happening in the light-duty market. And as I've said already, we're going to work with the staff on the IEPR to get them more data on the heavy-duty trucks because that's where we see the greatest growth potential over this time frame, the next two decades.

And I think there's significant potential, also, in the light-duty fleet market based on what we know today. But the heavy-duty truck market, I think, is where you're going to see the greatest growth.

And I think the AB 118 investment plan is already capturing that in the background discussion supporting various investments. I don't think the IEPR's there, yet.

One other relevant point is the PIER program, along with DOE and the air districts, has been putting money into R&D for heavy-duty, natural gas trucks and I think that's significant, supporting this trend.

On infrastructure, specifically, not yet captured in the IEPR and I talked briefly with the staff about it, this summer there was some major investments made relative to natural gas refueling infrastructure. Four companies have put in $300 million into clean energy fuels, just this summer. Four companies, $300 million to build approximately 300 new heavy-duty refueling stations across the country.

But that number in context, there are about a thousand out there today, across the country. So in one summer investments coming in -- now, granted, it's going to take two to three years to build those stations, if everything goes smoothly, but that's a 30 percent increased based on investments made this summer.

Just this week Shell announced a major investment in Canada for LNG refueling stations. They're going to be doing that in partnership with Westport, one of my member companies. But the word on the street is they're starting with Western Canada, with an intention to invest in the United States in the near term.

So you've got clean energy fuels, one major company, you've got Shell, and then the third news just this week Entergy, one of the big energy companies in the country, a Fortune 500 company, buying two other companies, Trillium and Pinnacle, who build natural gas refueling stations to, you know, in theory become a major player in the market to build competitive natural gas refueling stations. A lot going on in a very short period of time that I think significantly influences what we're likely to see as a growth trajectory for natural gas, especially in the heavy-duty market.

On the vehicle front, historically, the growth, the sales numbers have been in the transit bus market and a lot of that driven by air quality incentives and regulations. There's a shift happening right now, where the market is shifting away from that pattern of development to a cost-based, a cost differential-based market in the heavy-duty truck market, as well as the light-duty fleet market.

Look at companies like Waste Management, look at UPS, look at, in the light-duty fleet, AT&T and Verizon, thousands of vehicles that they're buying to run on natural gas primarily because of the price point differential with petroleum.

On top of that you have the Obama Administration adopting a plan for 2015 for Federal fleets and don't be surprised if there's a push here, in California, to get the California public fleets to follow that plan where all new purchases, starting in 2015, for Federal vehicles will be alternative fuel vehicles. Of course, they won’t all be natural gas, but some percentage of that pie will be natural gas.

So, you know, you’ve got low fuel prices, you’ve got growing fueling infrastructure, you’ve got a broader array of engine options. A lot is coming together, which I think suggests that, back to my tipping point comment earlier, the trajectories that we’ve seen in the past I don’t think are the trajectories we’re going to see in the future. And I think there’s enough evidence to at least talk about that in the narrative of the IEPR, even if the staff doesn’t change the curves that they presented today.

Finally, in the renewable fuels, which Gordon’s going to be talking about, there isn’t really any discussion of biomethane and that’s an important piece.

Commissioner Boyd and I have had a few discussions about which way is that industry going to go? Is it going to be predominantly for electricity supply locally or on the grid, or are they going to feed the transportation sector? The fact is we don’t know today, but there is significant potential for it to feed into the transportation sector either directly, you know, for remote fleets, or blended through a pipeline to greatly reduce the carbon intensity of fossil fuel natural gas.

And as you see in the Air Resources Board carbon intensity tables, that approach, you know, becomes one of the most competitive fuels based on carbon intensity in the next decade.

As I said earlier, I’ve spoken briefly with staff and have committed that I’m going to be working with my members and the staff to get as many of the players together in meetings, hopefully, face-to-face meetings, if not on the phone, to share the latest data to update the IEPR team on where things are going, which I think is markedly different from where they’ve been over the last five to ten years.

Thank you very much for the time.

VICE CHAIRPERSON BOYD: Thanks Tim. It’s interesting you noted some energy companies are really trying to become real energy companies. Others haven’t gotten the message, yet. Thanks.

MR. CARMICHAEL: Thank you.

VICE CHAIRPERSON BOYD: And the poor staff hasn’t even seen what I’ve done to their report. You should see the pages and pages of edits. And, anyway, it is a staff draft.

COMMISSIONER PETERMAN: And I'll also add, Tim, that Commissioner Boyd and I have talked with the staff that worked both on the transportation forecast, as well as 118, about some of the differences across those and I think there are some legitimate reasons for the differences. As you pointed out, one uses historical and customer base as part of the larger -- thinking about alternative fuels as part of the larger transportation infrastructure in the state, while 118 is more different focused and uses different resource materials.

And we've talked about how to better explain some of those differences between them. And I support your suggestion to get your comments and see what can be included in the narrative.

I think natural gas, though, is not unique in that the future is uncertain. It might be different from an historical trend and so we want to be careful to consider everything using the same kind of evaluation metrics, but can appreciate where you see the difficulty with that and particularly in fleets of natural gas and biomethane.

MR. CARMICHAEL: That reminds me of one comment I wanted to make. There's a rationale for government agency to take a more conservative approach when you're talking about what the future is going to look like, but given that the CEC is one of -- you know, I was going to say in California one of the agencies but, really, globally one of the agencies doing as much as any to push, you know, cleaner fuels and technology it's important for this agency to talk about the potential, even if you don't state it as this is absolutely going to happen this way. And so you can have that conservative baseline and say there's also the potential for this growth across these alternative fuels and technologies that we're talking about today.

And I think that's very -- I think you can cover yourself with the more conservative approach but also really help, you know, give that push by talking about the potential because a lot of people pay attention to what -- in the private sector pay attention to what CRC and ARB say relative to these topics. Thank you.

VICE CHAIRPERSON BOYD: Agreed.

COMMISSIONER PETERMAN: Thank you.

VICE CHAIRPERSON BOYD: Gordon, you're up.

MR. SCHREMP: Good afternoon, my name is Gordon Schremp, staff of the California Energy Commission. And I'll be not going through the low-carbon fuel center just yet; I'll probably start with the RFS2 stuff.

Thank you, Jesse, just what the doctor ordered.

Okay, Malachi covered earlier --

VICE CHAIRPERSON BOYD: Be crisp, Gordon, be crisp.

MR. SCHREMP: Okay, Malachi covered some of the --

VICE CHAIRPERSON BOYD: And Malachi's still here.

MR. SCHREMP: All right, so since Malachi's still here and if anybody has any questions, then I'll go into my next presentation.

(Laughter)

MR. SCHREMP: Some of the things I think maybe we want to be a little bit clearer on is we did a proportional share of the RFS2 obligations and we looked at the total amount of basically biofuels required under that according to Congress. And we assumed all that except for the biomass-based diesel was ethanol. So that's how we calculated our target for ethanol, our proportional share, and then that's the amount of ethanol that requires us to go to a lot of V85.

So we are using these total biomass numbers when we do that type of post-processing of the initial forecast.

I want to make a distinction because when we conducted the low carbon fuel standard analysis we did not use the cellulosic targets. We used targets that were much lower based on EIA's forecast, and I'll get into that in my next presentation, but I just wanted to point out that out.

The telling point of this slide is that the cellulosic biofuel mandate, as originally envisioned by Congress, has been downgraded by EPA every year because there's inadequate production capacity in the United States. That's still the gas three years running and next year is a billion gallons, or 2013 will be a billion gallon target that they will likely revisit.

So, what's important to note is that was lowered and the other was raised.

Now, I mentioned that the total targets can't be changed, that's incorrect and I think John Braeutigam's going to mention this, is that there is the ability to change to lower these numbers, all of them, even the total.

So, these are not sacrosanct, they're not set in stone, not being able to change unless Congress does it, they can actually be changed if those kinds -- if the cellulosic or something or other gets large, and other advanced, increasing it that much is just unrealistic based on market conditions.

So, we will see how this plays out, but for all intents and purposes we took these numbers on a face value when we did the post-processing. So in fact if they're lower or lowered, then the amount of E-85 you saw Malachi showing you in his slides would be less than indicated in the infrastructure, et cetera.

So this goes to show you the breakout and how aggressive the cellulosic is that may or may not occur. And our fair share, our proportional share's been about ten percent. And saw this, our ethanol use is expected to go over 3 billion gallons, so that's more than a doubling from where we are today.

And the main take away on these two slides is that it pushes down gasoline and brings up E085.

Now, Commissioner Boyd, you had a question from this morning about global diesel demand, refinery operations in the context of some of these issues. Well, in fact, RFS2 will depress gasoline demand and affect refineries, meaning they'll start to get a little bit out of balance so to speak. They're gas producing machines in California, they'll start to look, go more toward the European model. Demand for diesel keeps going up, demand for gas seems to decline.

It's also declined because of improved fuel economy and will decline further because of LCFS will displace more gasoline molecules, and LCFS will displace some of the diesel molecules.

It will depend, but we don't think there will be a lot of biodiesel use and I'll get into that later.

So, those regulations will put the California refineries under, I think, more pressure from an imbalance perspective. And so that kind of thing is what we believe, and I think Ryan Eggers will talk about in the crude oil analysis portion, why we think some of the scenario in refinery operations is to actually have some consolidation.

So it's really because of these other factors, improved fuel economy, higher prices that are sort of driving a growing imbalance in the product slate.

So I won't dwell on these, E-85 goes up, it depends on the scenario.

The important point on the infrastructure for E-85 is lots of dispensers and more vehicles. So on the dispenser side, it depends on how much fuel goes through the dispenser of how many you need. So, initially, there will be a lower through put, and this is normal, and then the through put will go up.

So, will it ever achieve sort of an average of 450,000 gallons per year per dispenser? It depends. If it's a sole-fuel dispenser, which most of the E-85 dispensers going in now are, they likely won't get to that level because those are modern, multi-fuel dispensers, three grades of gasoline, even diesel. So, 150,000 is probably a more likely plateau scenario where they could get to, but they'll start low and go up higher. So we're still talking, possibly, 10,000 or more. That's a lot of infrastructure in California that will have a -- have a cost.

Flex-fuel vehicles; the good news from this slide is that there seems to be plenty in our forecast to meet the E-85 demand requirements based on our assumptions on how frequently they fuel, and only more later in the forecast period. So, that's good news.

And then I'll go right into ethanol. Lots of ethanol, we're approaching the upper limit of RFS2, 15 billion gallons starts and you can -- you know, still using the program. You can use more if you want, but you won't really get credit. So it's very close to that in the nation.

California has also gone up and that's because there was a phase-out of MTBE in 2003, started and completed in 2004, that's why you see these two jumps. And then, again, in 2010 because preparation for RFS2 proportional share more ethanol is going to have to be used in California because we're sort of lagging behind the rest of the country so to speak because we were using a lower concentration than, really, any other place in the United States in their gasoline up to that point in time.

So, the infrastructure was modified and then the pipeline distribution company, Kinder Morgan, said okay, well, we’re going to go to ten percent, now, and that’s the majority of the gasoline through put through their system, so the entire market went.

Ethanol supply has continued to grow, primarily in response to MTBE phase out and RFS2. And what’s important to note here is that you’re starting to see the apparent demand line go below production and that means exports. Exports are occurring. So why, why would that happen?

Well, that’s happening for a couple of different reasons. One is there was a rapid build and over-supply of ethanol, more than can be put into gasoline to meet the ten limit.

Two, that led to a depressing market, in more ways than one, and relatively low prices to export opportunities. So what are we seeing? Ethanol going outside of the borders in record volumes and this has never happened before.

And most recently, the June numbers have just come in and they are -- they now set a record, they’re just a little above the April number there, the top point here. And I think about a quarter of that or 22 percent of that volume went to Brazil, that was the third, and Canada and the European Union were 27 percent, respectively, each.

So, that's the destination this time. Brazil will likely want more.

So the ethanol blend wall, ten percent, has been raised if you will, EPA has allowed E-15 in probably two-thirds of the fleet can go to E-15. But there are many other challenges that still remain, vehicle warranty, liability for misfueling at retail stations.

But as time goes by the blend will be exceeded and that's for two reasons. One is increased use of E-85 nationwide and in California, as well as some people in time likely going to E-15, more of that in different locations.

So this line, this increase in percent will continue, this concentration line.

Now, switch gears to Brazil, I just want to highlight from this slide that the significant differences from Brazil to the United States are plant size. As you see, around 18 million gallons per year at a typical Brazilian plant and 63 for in the United States, actual production volumes for 2010 per plant.

However, I guess one might say the efficiency in how much ethanol you can produce per acre is greater, sugar cane, no surprise. And so 655, you know, gallons per acre compared to 425. So that's sort of a take away from that slide.

Production had been going up and has plateaued a little bit recently. And also note there are different flavors on here and different geographies of Brazil, and these are production regions, but hydrous and anhydrous.

Hydrous is used in their flex-fuel vehicles and anhydrous is used in, I think, gas -- lower-level blends.

If I said that incorrectly, someone fix me.

All right, so this market is -- has been growing, of course, because that's how Brazil has a plan to meet a lot of their demand, but there are problems. Production this year is expected to decline approximately 18 percent.

So you had a question, Commissioner Boyd, about, you know, we're going to be depending on certain types of biofuels, well, production's going to be down in Brazil. Not only that, in recognition of demand that's growing at approximately 10 to 11 percent per year in Brazil, for ethanol, prices have become very high and consumers are getting a little upset.

So, a decision was made by the government to drop the blending rate from about 25, 26, down to 20 percent. So that is a way to, I guess, buy more time, keep a little bit more -- I mean keep a little bit more ethanol.

And what’s really going to happen is they won’t have to import as much ethanol and they’ll probably import a record amount of gasoline as a consequence.

So what does that mean for us, as analysts, when we look at, well, this is a good blend stock for low-carbon fuel standard, it’s a good blend stock for other advanced under the RFS2.

And so export forecast for next year of 530 million gallons, half a billion, don’t think so. That’s very unlikely that that’s going to happen. Brazil will likely have a record amount of imports of ethanol this year.

So, it’s very, almost disconcerting that the incremental supply one would look for to potential be available from Brazil, of the right kind of biofuel at this time, the low enough carbon intensity may not be there.

So it leads right into your question from this morning is what kind of potential is there for ethanol shuffling, the Sao Paulo/Houston shuffle, are quite high. That is a way to get adequate supply of Brazilian ethanol into this market. The Midwest ethanol goes down a boat, unloads, picks up Brazilian cane ethanol comes back to the United States, but at a price, and we'll talk about that later.

So there are, I think, concerns about we don't believe incremental supply of Brazilian ethanol will be available, but we think swapping is a possibility, but at a much higher cost.

And that infrastructure to bring, say, Brazilian ethanol in may not be as robust as we would like for marine facilities in California, but it hasn't had to have been up to this point in time. As you can see, that would be the green stack bar, very little, and this is really, mostly imports from Caribbean-based initiative companies.

But none in 2010, mostly rail, 96 percent, averaged about 91 percent over this period of time. So, rail import can serve Brazilian ethanol because it could come through Texas. It could come through Houston, in the ship channel, be offloaded and put on a rail and that same rail car that's coming from the Midwest now comes from Houston.

So, it's feasible, it would take a little bit of work to complete the last part of that project, Kinder

Morgan's project in the Houston ship channel, but this is at least feasible and we have a pretty robust and dependable rail infrastructure in the state.

Shift gears to biodiesel, biodiesel production has rebounded from 2010, primarily because of the blenders -- the dollar-a-gallon tax credit was sort of not in play for most of 2010 and not until the end of the year; retroactive, but too late then.

This year in play, more of it's happening. And I think there just was a record production of biodiesel in, I think, last month, or June, the last figures available, I think, yeah, 95 million gallons.

So this figure will probably, now, this is an estimate we had from a couple of months ago for 2011, it will go up and it will likely beat the record for 2008.

Why? Higher demand for biomass-based diesel under RFS2 and the reinstate of the dollar-a-gallon blender's tax credit which I think is scheduled to expire at the end of this year.

So, are we back to the same down and up, down and up? We will see.

Consumption in California very low, has been declining. Primarily, that's a price reaction, very expensive biodiesel, biodiesel in the Gulf Coast and in Chicago yesterday, selling for between $5.90 a gallon to

$6.03 a gallon. I would consider that expensive, especially because it's wholesale.

So, biodiesel is expensive. The feedstock's very expensive. So why you don't see a lot being used here.

Now, someone might think these figures are pretty low. Well, if California used the average concentration of biodiesel in the United States in 2010, our five million would be closer to 14. So, just to put it in some perspective, so California's using a little bit less. And I mean that's just the way it is because the infrastructure in California may not be as robust as other areas.

And what I mean by that, if you want to blend five percent biodiesel, you have to have a storage tank at the distribution terminal for B100, then you may blend it into your carb diesel and make biodiesel, but not until that point.

So that we understand there is sort of a lack of that kind of capability at this time, but as demand goes up, which we believe will happen because of the LCFS that, hopefully, more of that infrastructure will be put in.

Just supply, this just goes to show you a lot of exporting was occurring before Europe sort of tightened up that behavior to prevent it, countervailing tariffs and all, and then the line's gone back up. So, more of it's going to stay here because of the RFS2 and the dollar-a-gallon reinstatement.

And a small percent, much smaller percent, now, of course, being exported.

So, here's the concentration. As you can see, since January it's been going up steadily every month, so this is a resurgence of ethanol or biodiesel blending to actually a record level in the United States. And so we expect this to continue rising somewhat, but the economics are very challenging.

So, some of the issues that I haven't touched on, besides the economics and the infrastructure, is a five percent blend limit is something we're assuming in California. There is a concern about incremental air pollution, of NOx, oxides of nitrogen, and sort of saying that maybe B5, up to B5 levels there may not be a NOx mitigation required. We will find out more as the Air Resources Board works through that regulation. But blends above six percent, six to 20 will require some sort of mitigation, we're just not sure what that is, yet.

And there are some warranty issues being rescinded about B10, and last take away is renewable diesel really doesn't have any of these other sort of issues, if you will, except higher feedstock certainly is something that renewable diesel can have, depending on what they're utilizing.

So that kind of drop in fuel does have some more desirable attributes.

Spend just a few minutes of my time here to finish up on agricultural. I understand that I believe there's -- Commissioner Boyd, there will be a forum on the 22nd of September, is that correct, to discuss some of these issues?

VICE CHAIRPERSON BOYD: Yeah, I can't remember if it's the 21st or the 22nd but, yes, a joint Food and Ag/CEC forum on biofuels and agriculture, and the nexus -- well, bioenergy and agricultural and the nexus there between. The hearing notice should go out today, that's why my advisor is missing he's trying to get it fixed.

MR. SCHREMP: Okay. Well, thank you. So, we'll make sure the people on the list serve for these proceedings will also receive that notice as well, when it's available.

So, corn demand for ethanol, no surprise it's been going up rapidly, as has production for ethanol. And this will plateau. In a couple of years the 15-

billion gallon limit will be reached, so it really won't, you know, get much more than that.

But as it's gone up, the percent of corn used for this purpose has risen rather dramatically and is not the top use, if you will, of corn demand in the United States and has resulted in, you know, some pressure on corn commodity prices, debatable on what portion is due to this increase in demand but, hopefully, being discussed on the 21st or the 22nd.

VICE CHAIRPERSON BOYD: That's -- let me interrupt you, Gordon, it is the 22nd, you were correct. And the chart you just showed is some of the genesis of the decision to have that hearing and the Investment Plan, AB 118 Investment Plan that was just released by this Agency a little late into this fiscal year contains zero dollars to provide for any incentives for the California production of ethanol from corn, and that was quite a controversial issue.

Just like in prior years hydrogen was always a controversial issue. So, not very popular politically, very controversial with food versus fuel, extremely controversial in fuel versus the cost of animal feed has led to us having this -- making the decision we made in having this joint forum on what the future might be for ag and bioenergy. Enough of a commercial.

MR. SCHREMP: Okay, thank you for that clarification.

This is just another way of looking around the percent, the total number has been basically pushed up by an increase in the red bars, the use to make fuel ethanol.

Now, one way of making more corn available is to increase the yield and that's been progressing at a rather steady clip, as you can see here. Not quite a record in forecast for 2011, but close to 160 bushels per acre, so rather impressive.

And that's allowed the agricultural community, collectively, to not have to plant as much corn as in the past.

And as you read down at the bottom here, I mean the amount in 2010 was almost 30 million acres more than 1917, the record, yet produced a whole bunch more corn. Why? Because of the improvements in yield that are accomplished through, you know, GIS fertilizer application, and genetics, primarily, over the last 20 years. So that is continuing and is forecast to continue.

Now, what's interesting about another issue that comes up with increased corn is, well, you're going to use a whole bunch more acres of land, so it's a land issue. Well, actually, the amount of land is sort of staying flat that's being used. So if you see this, these are the top three crops in the United States. And if you took the top eight crops, you'd be upwards of about 250 million acres, so just a little bit more than this.

But as you see the line, it's going down, so it's almost flat or going down a little bit, it's about a 1.9 percent decline over this period.

Well, how can that be if demand for these crops is going up and actually their production is because, once again, the yield's continue to grow for all three of the main crops, and others, between 10 and 15 percent over the forecast period, not per year but over the forecast period.

So, still an assumption of continued yield growth.

This one is interesting, showing a decline in the amount of corn as a percent and not because of other uses going up, because the assumption made by USDA is that there will be a yield improvement. I take a bushel, how much ethanol do I get?

Well, they're looking -- they're talking about a six percent increase over just the next four years. Well, you know, we probably think that may not -- this might be overly optimistic because in the period 2006 through 2010 the yield actually declined. So, that's sort of a questionable assumption, but it wouldn't change the numbers that much.

Final slide, two issues that have, I think, routinely come up have been corn uses a lot of water, you're going to use more corn than more water, and it's a scare resource in many places in the U.S.

Well, actually, it sort of depends if you're talking about the water used to grow the corn, that's a small percent when it comes to irrigated -- irrigation is 15 percent. So, the vast majority depends on, you know, the skies, it has to rain, but not too much to flood me out.

So, assuming that stays constant then, you know, shouldn't have a lot of water use.

But local water use to process corn in a new facility may in fact be a legitimate issue in some areas where, depending on where the plant is sited.

But fertilizer use is another issue, it has gone up, but only about eight percent over a period of 30 years, and the yield has gone up 68 percent. So, yield increases of that magnitude are not because of an eight percent increase in the nitrogen application rate, are in fact these other reasons, these genetic reasons of why you have much greater yield increases.

So, be happy to answer any questions you have at this time.

VICE CHAIRPERSON BOYD: No more questions up here. Anyone? There's a hand. Welcome.

MR. BRAEUTIGAM: Good afternoon. I'm John Braeutigam with Valero Energy Corporation.

Gordon, can you go back to slide number four, your RFS2 slide? And we -- Valero will be providing written comments, also.

VICE CHAIRPERSON BOYD: Thank you.

MR. BRAEUTIGAM: I'd like to make about five points about this, I'll try to be pretty brief. If you look -- like you said, we've scaled back, EPA has scaled back the cellulosic amount each year. I would suggest that your base scenario should be the EIA projection, not this projection. They're going to continue to scale it back and the reason is capital.

And you can't -- you just can't overcome economics. A corn-based ethanol plant, 120 million gallons a year, in 2008 costs $150 million because you'd have to put in additional technologies to qualify it, now, for 15 percent greenhouse gas reduction, would cost $200 million. That's a 1.67 dollars per gallon of capital.

Cellulosic ethanol plant, $25 million, $200 million dollars, $8 per gallon of capital.

And I don’t want to name the technology provider’s estimate there.

Valero is one of the largest ethanol producers in the U.S., we are looking at cellulosic ethanol, we’re looking at renewable diesel and other advanced biofuels. These are numbers that we’re looking at.

Renewable diesel, 135-million-gallon-a-year plant, $350 million, $2.60 a gallon capital cost.

If you look for capital recovery of 20 percent, plus your cash operating costs, your cellulosic, now, is running about $1.65 a gallon. Corn is $2.45 and that would be about a $6 or $7 a bushel corn price.

The renewable diesel, if you’re going to use, make true renewable diesel, the hydrocarbon equivalent or look-alike, a cheap feed is $3.50 a gallon. That equates to $147 a barrel.

So your renewable diesel, before you put in operating costs, just your feed, itself, is going to only be economical when you -- because of something like the LCFS or the RFS2.

We really believe that when you look at these numbers the actual cellulosic amounts are going to be closer to the EIA because the industry isn’t going to --

where's the capital going to come from, okay.

And we think the EPA will scale back both the total advanced biofuel requirement by the same amount they scaled back the cellulosic each year, when they issued a waiver, and the total renewable fuel standard.

And we see that happening for many years to come, just because if you look at the total advance, you know, one point -- my glasses aren't that good -- 1.1 million, 1.5 billion in 2016. That's not going to be there. And the cellulosic waiver allowances that you can buy from the EPA cannot be used against the advanced renewable volume obligation or the total.

So they're going to have to scale those two back, they have the authority. EESA gave them that authority, that's why I would suggest that you --

VICE CHAIRPERSON BOYD: They have the authority, do they have the political wherewithal?

MR. BRAEUTIGAM: Well, what they've used the excuse of that, the Brazilian ethanol was there. And now, for what they proposed last year, they were using that excuse again, even though none's come in and it's $1.50 out of the market.

At some point I think they're going to have to do it because what's going to happen is the industry, not every company, but the industry will go into default on the RFS2 because that advanced biofuel is not there. We need 800 million gallons this year. The industry isn't even producing that much.

There was a deficit ran last year and the industry has to make up that deficit this year, the same parties can't make a deficit run two years in a row.

Valero's been saying there's an RFS2 train wreck coming, not just an LCFS. Both of them have major problems, too ambitious.

COMMISSIONER PETERMAN: I think your point is well taken. And I would ask staff, if time permits, a sensitivity test, the results with the EIA cellulosic projections, although appreciating I think the baseline should reflect what's current statute, but let's start there and see where it goes.

MR. BRAEUTIGAM: I think that would be a good sensitivity.

Two other quick points; as Gordon said, the exports are going to Brazil. You could do the Sao Paulo shuffle, but it's still an awful lot of volume to move.

The IEPR does a real good job of pointing out the barriers, but then it tends to go and says don't worry, all will be well.

I mean even your base case with that much E85, on the other graph, once again where is the capital going to come from for the E85 pumps?

And by the way, E85 is only legal in flex-fuel vehicles today. It is illegal in 2001 and later model year cars. The health effects testing has not been submitted and has not been approved by the EPA. And the survey of the retail outlets is not up and running.

There's several conditions required before it can be sold in those 2001 later vehicles, that haven't been met yet.

That's all, thank you.

VICE CHAIRPERSON BOYD: Thank you. Another question?

MR. STEVENSON: Thank you, Commissioner Boyd, this is Dwight Stevenson, with Tesoro.

I think I heard you say that you had a question about the wisdom of a policy that was going to be moving ethanol back and forth in order to comply with the low-carbon fuel standard. A very keen point to be made and this is what I think you ought to be concerned about in terms of what can show up in the Sacramento Bee.

And it's not just a matter of cost, it's also that the greenhouse gas emissions that we think we're getting, we think we would get in California, the reductions, would be completely offset by either gasoline imports into Brazil or the ethanol that would be shuffled back to it.

So I think I commend you for looking at that issue.

And as far as the -- I think I've heard it deemed a theory, as far as it may be happening, it has happened. There have been ships that have taken ethanol out of the Gulf Coast, down to Sao Paulo, discharged, back-loaded, back to the U.S. Gulf Coast, so it is happening.

VICE CHAIRPERSON BOYD: Why is it happening if there isn't the LCFS, yet?

MR. STEVENSON: The primary driver was the EISA, it was the RINs credits for advanced renewable.

VICE CHAIRPERSON BOYD: Speculation.

MR. STEVENSON: Sorry?

VICE CHAIRPERSON BOYD: Speculation or just --

MR. STEVENSON: Well, it's a description from the trader who was doing it.

VICE CHAIRPERSON BOYD: Okay.

MR. STEVENSON: That's what he said.

COMMISSIONER PETERMAN: Can you just clarify that, was there a requirement, an EIS requirement that was in place now that they were trying to meet?

MR. STEVENSON: Yeah, the RINs that are -- the RIN credits that are generated from the advanced renewable paid for that.

COMMISSIONER PETERMAN: Okay, thanks.

MR. STEVENSON: And, of course, at no, now, greenhouse gas benefit. In fact, obviously, a little bit of a cost there.

And as for the -- thanks, Gordon, for responding on this last slide, was that -- was that for me?

MR. SCHREMP: The very -- the very last slide?

MR. STEVENSON: The very last slide, yeah.

MR. SCHREMP: Oh, did you say --

MR. STEVENSON: Yeah, I've been asking these questions and so I appreciate this answer. But I wanted to respond that the difference between -- I guess the term is all things being equal, so there is going to be this growth and, you know, thank goodness that we've got an ag industry that does so good a job of providing food, and they're going to continue, I hope, to provide more and more bushels per acre.

But the point is that if you impose the ethanol consumption, all things being equal, there will be not just the normal three percent or one and a half percent growth, but there will be a requirement for crops being grown out of cycle, with irrigation, and with more fertilizer.

Is that clear or --

MR. SCHREMP: Well, I'm not sure that that's exactly clear but I think --

MR. STEVENSON: Okay.

MR. SCHREMP: -- certainly the second sub-bullet there, you know, assuming the ratio remains fairly constant it's -- I mean, for example, since clearly 2007 circa data, and we're studying 2011, has a lot of this corn acreage shifted to places that are purposely using irrigation.

Don't know the answer to that question, so there could be disproportionate amount, you're right. So, all things being equal, no, if they're not -- if they're unequal and the area's being targeted for corn use, especially now, with very high prices and some of the farmers chasing some additional opportunity --

VICE CHAIRPERSON BOYD: Right.

MR. SCHREMP: -- where is that crop being grown? And if they want more certainty because of the very high price, maybe they go to an irrigation business model and not dependent on weather, because the value is so high. So, you're right, we don't know the answer.

MR. STEVENSON: And that's my point is, yeah, the incremental corn is going to come out of that, it's going to come out of more water and more fertilizer being put on the ground. And so you can't just look at the average from an incremental demand, you've got to look at the incremental effects.

And it's called farming intensity and so far CARB has not yet considered that in -- they've got indirect land use change included, but they haven't got the intensity, farming intensity.

Thank you.

VICE CHAIRPERSON BOYD: Thank you. Okay, let's move on to the next item. Mike Waugh, from ARB's going to talk about the Low Carbon Fuel Standard.

You're only -- we're only two hours behind, Mike, so -- I'm not telling you to speed it up. I know people have been waiting, sitting on their hands waiting for this one.

MR. WAUGH: Thank you and good afternoon Commissioners, the CEC staff, other stakeholders.

I was asked here to give an update on the Low Carbon Fuel Standard, and apparently to break up back-to-back Gordon presentations, so I hope to accomplish both.

What I'm going to do here, briefly, today is go over the goals and the benefits of the Low Carbon Fuel Standard, kind of a reminder of why we have it, look to see how we're proceeding on our 2011 implementation.

We have in process right now two large efforts;

one is a formal review of the LCFS, with an advisory panel, and the second one is proposed amendments to the LCFS.

As a reminder of the LCFS, the goal is to reduce the carbon intensity of the transportation fuel by ten percent by 2020. We consider a full lifecycle in this assessment of the production and transportation use of the motor vehicle fuel.

We do have separate standards for gasoline and diesel. However, if one of these standards is over-complied with and credits are generated, it can be used for the other standard.

The LCFS is estimated to reduce greenhouse gases by 16 million metric tons of C02 equivalent by 2020, which is about ten percent of the overall GHG reduction goal of the larger AB 32 program, so it is a sizeable part of California’s goal to reduce GHG emissions by 2020.

These emission reductions can be achieved through the use of lower carbon intensity biofuels, you know, ethanol, biodiesel, cellulosic fuels.

Or there is a distinct advantage, we think, with the Low Carbon Fuel Standard over the Federal RFS2 program in that electricity, hydrogen, biogas, natural gas can also play a role. And based upon some of the presentations given already, there’s obviously a very healthy interest in these other alternative fuels.

Another goal of the LCFS is to reduce the amount of petroleum concerned and dependence on foreign oil, and we’re also hoping that we establish a model for regional and national standards as well.

2011 implementation -- 2010 was a reporting year, only, 2011 is our first implementation year. There’s a modest requirement this first year and that’s a quarter of a percent of carbon intensity reduction for 2011. The LCFS is back loaded in that the first few years are pretty modest and then the curve really dips down towards the end of the decade, especially the last three years.

Already, quarterly reporting requirements, we’ve had the first and second quarters reported. This is where the regulated parties report their credits and deficits. A credit is when you introduce a fuel that has a CI that’s lower than the standard and a deficit is when you introduce a fuel that has a CI or carbon intensity that’s higher than the standard.

And then so you can generate credits on a quarterly basis and they’re available for purchase or transfer.

One of the things that the -- one of the programs that we have and I'd like to give you an update on, and Gordon's next presentation is based a lot on some of this data that we shared with the CEC, is our Biofuel Producers Registration Program. It's a voluntary program. One thing that's not voluntary is they have to show evidence of physical pathway, which means they have to show that they have actually brought biofuel into California. So, that's required by the regulation and we use the registration program as a vehicle to get that requirement.

But also, the producers can provide regulated parties with claimed CI values. Essentially, it's either in the look-up table or they've gone through our method two to get a CI associated with their biofuel, and they can show what their value is and regulated parties can find them via our registration program.

VICE CHAIRPERSON BOYD: Mike, do you need evidence of a physical pathway or do you need evidence of the green molecules showing up here?

MR. WAUGH: Physical pathway. You know, in the case of, for example, of like biogas that's introduced into a pipeline, we don't need the molecules to be here. If, for example, a biogas is introduced in some other state into a natural gas pipeline that comes to California and a similar volume of gas is pulled out on this end to be used for transportation purposes, we would assume that that biogas, for example, has come to California. We're not interested in the molecules, themselves.

VICE CHAIRPERSON BOYD: Well, maybe Commissioner Peterman and I can give you a warning of something that might be coming your way. We, as an agency, have been catching a lot of grief over the assignment of renewable portfolio standards to biogas from out of state. And there's a feeling on the part of some people in high places that you need to prove that the molecule actually showed up at the burner tip in that case, which is a physical impossibility.

So, you may have heard about this, but it may be coming your way or maybe you have more friends than you do that will shield you from this, but in any event interesting. That's why I asked the question.

MR. WAUGH: I appreciate the heads-up, Commissioner Boyd. I'm not sure, by the time we get through this presentation, we'll see if we've got more friends than you do or not.

COMMISSIONER PETERMAN: I'll also add that we're having a workshop looking at delivery pathways for biomethane, for RPS compliance, on September 20th, here at the Commission. And I know you have a very busy week, so stop by for that, first, or send anyone you know. That would be great to just have someone from your team listen in or attend to see where the discussion's going.

MR. WAUGH: Thank you, Commissioner Peterman. I think the mode these days is that we go to meetings all day and work in the evenings and on the weekends.

So, I have some dates coming up in my presentation, too, so you invite us to your party, we invite you to our party.

We have a lot of facilities registered in our program, over 15 U.S. facilities, now, and that represents 10 billion gallons a year of capacity. We also have some Brazilian facilities registered. They are in a different table because they haven't provided evidence of physical pathway and that they haven't actually sold ethanol in California, yet.

We're just now looking at the second quarter data, so unless there's a surprise there, we haven't seen any Brazilian ethanol, yet, in California the first part of this year.

This is very important, this is what I call our method two pathway. Method one is you look up in our look-up table for a CI that applies to you. You could be, for example, a dry mill, a dry distiller of grains, insoluables, natural gas plant and you get a 98.4 in the look-up table. Or if you think that you're doing something better than that, then you can apply for a different CI. And we've had quite a few facilities apply for new fuel pathways with lower CIs.

We had an EO hearing in February, where we took eight -- 28 pathways to the executive officer. Twenty-five were from applicants, most of them were from corn, there were some Caribbean-based initiative ethanol, and then we developed three, ourselves.

We also posted for use, in June, some more pathways. Right now, because what we've decided to do through our reg advisories, is that we post -- when we are going to present for approval to the EO or to the Board a new pathway, we'll post it and we are allowing regulated parties to use those CIs until, you know, until we can -- or at least before we end up with an official approval by the EO or the board.

We have some, I know we're talking about the difference in CI between Brazilian ethanol and Midwest corn ethanol, for example, but we've seen some really lower CIs come through, there have been a lot of innovation in some of the plants in the Midwest. Use of waste heat more efficiently, using waste heat, also greater use of biomass as a fuel.

And some of these corn ethanol plants have CIs that start to approach those of Brazilian ethanol and one actually is lower than Brazilian ethanol because they use a waste wheat slurry, as well as a feedstock.

So, we think this is working as planned. There are two driving forces, really. One, if these plants can make their product with lower operating costs, that’s the bottom line for them, but they get a double benefit because when you’re more efficient you get a lower CI and there’s value in the market for that as well.

This is the first quarter 2011 reporting results. As I mentioned earlier, you get credits and deficits. And staff looked at the first quarter and you can see that the number of credits generated were greater than the number of deficits generated.

So, you have about 150,000 metric tons of deficits and these are, again, fuels that are higher than the standard, and you’ve got 225,000 credits of those lower than the standard. So, there was a net 75,000 metric tons credit generated in the first quarter. And these credits will be available for use, for regulated parties, should they not be able to, perhaps, procure fuels to meet the standard.

And how they were generated the first quarter;

the four bars to the left are all ethanol, so most of it was generated by having lower CI ethanol blending into gasoline. There's some natural gas there, and biodiesel. And the one on the end is "other" and the "other" is electricity and hydrogen. There's a lot more electricity out there.

This was reported as in terms of direct metered electricity. So, there is an effort right now to go out and define more of these EVs, figure out how to estimate how much electricity they're using and get them into the program.

I think as Eileen Tutt said this morning, one of the things that we want to do is to get as many credits into the LCFS program as we can so that some of these credits aren't abandoned out there, but can be brought into the program and used for compliance.

COMMISSIONER PETERMAN: Can you say again what's an "other" is that electric?

MR. WAUGH: That was electricity and hydrogen, yes.

COMMISSIONER PETERMAN: Okay.

MR. WAUGH: Yes. And like I said, that should be more than that. I think there's some people who aren't quite familiar with the LCFS so we expect natural gas, and electricity, and hydrogen all to go up.

This is a big effort. We have a formal review of the LCFS. It’s required by the regulation. The first one is due to the board by January 1, 2012 and the second one January 1, 2015. We are, in fact, doing the first formal review at this point.

The reg requires the executive officer to convene an advisory panel, that’s been done, and the next slide will go into that.

The regulation identifies minimum topics of the review, so the programs’ progress against the LCFS targets, fuel availability, economic and environmental impacts, advances, challenges related to the low CI fuel production in harmonization with the international and Federal programs.

A lot of this effort here is similar to what the CEC is doing for the IEPR. Essentially, there’s a lot of overlap here and I must say right now that I appreciate the dialogue that we’ve had with the CEC staff. They’ve shared their assumptions, we’ve shared some of our assumptions and so we do have a lot of work here.

We’re doing a similar analysis with regard to LCFS targets and compliance, as what you’ll see in Gordon’s next presentation.

We have our number one hourly employee on this program and that would be Mike Scheibel, so we feel confident in his abilities.

The advisory panel, itself, there’s about 40 members of industry, academia and NGOs. In fact, several of them are here today. It was first convened in February. We’ve added two topics, in addition to the ones that were in the regulation, itself. One is high carbon intensity crude oil and the other is a credit trading program, so these were added by the advisory panel in the February meeting.

The panel’s met four times, providing feedback to ARB staff proposals. Typically, we’ve been sharing outlines of chapters and then writing up the chapters, and this is continuing. And the final meeting is in October, we hope to have the draft white paper available. I think some of it is coming out in pieces at this point. There are some things that will be late in showing up just because they’re a little bit more challenging pieces of the puzzle.

And we’re going to discuss this program review at the December board hearing.

The other concurrent and very important effort that we have, we’re looking at proposed amendments to the LCFS regulation. These are the larger ones, the opt-in/opt-out provisions. The regulation now allows people to opt in. This will be clarifying language so they can feel more comfortable of this is how I opt in and if I want out, this is how I opt out.

Also, there's an enhanced regulated party provision. Some of the upstream fuel providers, fuel distributers wanted to become regulated parties so that they could generate credits. Right now, the regulation only allows regulated parties to hold credits, so a third-party broker, for example, couldn't start buying up credits and manipulating the market. So, you have to be a regulated party to hold credits and some of these have indicated that they would like to voluntarily opt in.

Credit trading process; credit trading's allowed today. This, again, is clarifying language as to how the process is going to work.

Certification process for method 2a/2b, right now it's a regulatory process and that is a burdensome process on staff. We think that we can go to a certification process. There are several of these at ARB. We would maintain the technical rigor of 2a/2b and also the public input of the regulatory process, we'd maintain that in the certification process.

This is for streamlining so that we can get more of these processed and out the door.

Also, in high carbon intensity crude oil we're looking at revisions. I want to make sure that I make this point, that they're going to be talking about HCICO. I don't know who decided the first "C" was silent, but that's how we say it.

We'll be talking about HCICO later. And the current regulation has provision for HCICO. When the board approved our reg two years ago, they recognized that some crude oils take more energy to produce than others and they agreed with staff that the high carbon intensity crude oil, there was a deficit created when those were produced and brought into California, again, going with the full lifecycle analysis that we do.

What we're doing now with regard to HCICO is we're working with the interested stakeholders and there are several, many, plenty on should we deal with HCICO differently than what the current regulation deals with it right now?

Electricity regulated party, we've got language in the reg, we're making revisions to that. I don't need to tell you at this time of the day there is a lot of interest in electricity credits.

And then there is the potential revision to land use change values. We have a contract with the professors at Purdue to look at sugarcane ethanol, corn ethanol, and soy biodiesel, looking at the land use change values for that.

The potential impacts from the analysis, if the land use change values change significantly, you know, if they alter the soy, corn, and sugarcane biofuels that may alter the baseline and, therefore, the compliance curve. So, we don't have the answer for that, yet, but we are aware that since the baseline was gasoline, with ten percent corn ethanol, if that value for corn ethanol goes down then the baseline changes and the compliance curve would change as well.

On the HCICO, we have offered up a handful of options to deal with existing language and we're engaged in conversation with stakeholders there.

And how we ultimately end up dealing with HCICO, it may affect the generation of deficits.

And, finally, in crediting trading and opt-in revisions we've -- those are clarifying procedures, as I said earlier. And we think that once the credit trading program gets up and the opt-in revisions kind of show people how to get in, that we think we're going to attract additional credits into the program, which is very important to us.

Here's our party dates; a workshop next Wednesday, in the morning. We have a workshop on land use change. In the afternoon we are talking about the other proposed amendments that I just mentioned, previously.

For the advisory panel, on September 29th we have a public meeting to discuss progress on the advisory panel. And the final advisory panel meeting is on October 27th.

Our board hearing will be -- right now it's scheduled for December 15th, in Sacramento. We will be taking to the board proposed amendments, the LCFS formal review, and sustainability which I didn't mention earlier, but that's a third effort that's going forward.

Here's contact information. As I said, I'm Chief of the Transportation Fuels Branch. Floyd is Chief of the Alternative Fuels Branch and he is back against that wall there, so he and I share the LCFS at this point.

And we've got a couple of key staff members here; Michelle Buffington is advisory panel co-chair. I think those, obviously on the panel, are familiar with her.

And then Aubrey Sudeco works in Floyd's branch and she's coordinating the record revisions.

So, I'd be happy to answer any questions that you have right now or I can go back and say if there's not enough time, there's plenty of opportunity. Thank you.

VICE CHAIRPERSON BOYD: Thank you, Mike, appreciate you being here.

Any questions? I don't have any questions about your presentation, I appreciate the -- a better understanding and clarification.

Let me throw one thing into the debate, coming from the stand point of an Energy Commissioner versus an Air Board member, let's just say, and that is as we sit here and worry about energy security, energy diversity, et cetera, et cetera, I know theoretically energy security doesn't buy carbon intensity credits, at least at the present time. But I, for one, have talked about this for a while and I, for one, am wondering as a nation state when we make final decisions about where we want to go and from whom we want to buy our transportation fuels, and shuffling that takes place before or after, if the idea of energy security points maybe isn't something we consider.

Now, I know that -- well, that may or may not give you carbon. I mean I worry about shipping stuff halfway around the world in dirty tankers, and having some third world country burn our stuff which, if it's in the Far East comes back to this state as a criteria air pollutant in the stratosphere.

I just don’t know, when you talk about doing full systems analysis of things, I don’t know if we’re taking everything into account.

But energy security is not something that totally gets points, but maybe it would enter into a discussion about where you shuffle stuff to and what the consequences are. And in the shadow of the tenth anniversary of 9/11 one thinks about energy security.

And I’m suddenly reminded by that comment where I was on 9/11, I was with the CalEPA Secretary Winston Hickox, with the present, now, head of the Council on Environmental Quality, and the former executive director of this agency in Nebraska, trying to make peace and understand ethanol and corn ethanol, and it turned out to be a very sad, if not interesting experience.

In any event, just some thoughts with regard to my thinking and the kind of thinking we need to think about. And maybe it was stimulated a little more in the last year by participating in the production of a second report by what I consider an illustrious group of people called the Cal STEP group, which generated a report several years ago that, as far as I’m concerned, led to the existence of AB 118.

This report tried to inject -- it suggested a greater injection of the question of California energy security into the debates that were going on in this State on the subject. And it’s a very prestigious group of folks from the environmental community, industry, not much from government, but et cetera, et cetera.

And so it’s something to think about, I think, when you’re a policymaker here in the State dealing with energy.

So, it’s just I’m just sharing that with you because I don’t get many audiences with ARB. So, thanks Mike.

MR. WAUGH: Thank you, Commissioner Boyd. You know, we had several discussions with representatives of Canada and we’ve talked about that. We read recently about carbon capture and sequestration that may occur up there and we’re excited about that part as well.

And I think that the different options that we’re discussing with regard to HHICO, some of those options would, I think, at least temper some of the potential crude shuffling. So, we’re cognizant of that and we’re working with stakeholders on that.

VICE CHAIRPERSON BOYD: Any questions from stakeholders? There’s the first hand.

MR. STEVENSON: Dwight Stevenson, with Tesoro. Could you go back to slide 8? So, slide 8 shows a net balance of the deficits and credits. And I'm not sure how to make this point, but I guess I'll ask the question. Are you saying that all the credits shown there are certain and allowable by all those parties that generated them?

MR. WAUGH: Well, Dwight, as you're probably aware, that since the HCICO issue has not been address, yet, we gave three options with regard to how to handle credits generated in 2011, while HCICO was still uncertain.

One of them was that you can use all these credits in 2011 and then wipe the slate clean and start over in 2012.

The second option was to maintain these credits. Certainly, some of them would be frozen so you couldn't use them until we figure out how they would be discounted by HCICO.

And the third was that if there was a default value applied to potential HCICO, because right now all we have is non-HCICO, which is like three-quarters of the crudes, and one-quarter of the crudes is potential HCICO.

So, until we can get the actual HCICO identified, some of these credits would not be available for use unless you chose a default value for your carb and diesel.

MR. STEVENSON: Okay, so some of these credits are not going to be available for use in following years?

MR. WAUGH: Yeah, the sooner we get the HCICO issues answered then I think we can adjust these credits and they'll all be good, what's left.

MR. STEVENSON: Okay. But some of them may not be?

MR. WAUGH: Some of them may not be, yes.

MR. STEVENSON: And it's an interesting graph because it really shows -- this is a quarter percent and so next year it's going to be half percent, and so the deficits that are going to be generated are going to be roughly twice that amount. And it's interesting when you go to that next level of deficits that what's happening this year is not going to be sufficient for compliance next year.

MR. WAUGH: Well, as I said, I think we're going to get a lot more credits, too. I think that that bar's going to go up because I think people are going to go out and search for electricity credits, natural gas credits. I think that with the method two we're going to get lower and lower CIs for some of the corn ethanol. And, you know, perhaps if some of the Brazilian ethanol shows up, the credit bar, itself, will also go up.

MR. STEVENSON: And I’ve got a -- so that’s -- thank you for that. I’ve got a point to make here as concerning the certainty and I’m -- I’ve yet to see CARB or the CEC make a full projection, year by year, even just for the near term as to how that you expect the State will, you know, comply with the Low Carbon Fuel Standard.

And you mentioned the Brazilian ethanol and that cost, of course is in the -- you know, in terms of gasoline price, 10 to 15 cents a gallon increase with that material. Clearly, in the next year or two that’s going to be happening, at least from my stand point.

But what is lacking here is some understanding. You know, we ought to be describing to the State -- you ought to be describing to the State what’s going to happen and how much it’s going to cost the State. Thank you.

MR. WAUGH: Yeah, Dwight, thank you. Just to let you know that, you know, that effort is being done for -- it’s for the advisory panel. You are on the advisory panel, so we are doing the economic analysis, we are doing a fuel availability, we are doing that kind of analysis, and so we hope to share that with you next month.

MR. STEVENSON: Some time before the panel is ended?

MR. WAUGH: Yes, that’s the goal.

MR. STEVENSON: Oh, okay.

VICE CHAIRPERSON BOYD: Okay, Mike, thank you very much.

MR. WAUGH: Thank you. Guess it’s back to Gordon.

VICE CHAIRPERSON BOYD: You’re getting off easier that I thought you would.

Now, Gordon, the next header has the heading of “Case Analyses”, but the list that I’m provided has a whole bunch of issues on it. My reaction is we’ve talked an awful lot about some of those. So, are you going to be able to lightly skip over some of these and talk a little bit more about others where there hasn’t been much discussion?

Like, the first item says “Transportation and Electricity Demand Forecast.” Well, we’ve certainly talked about that.

The “Availability of Electricity Credits,” maybe that deserves a little more discussion.

“The Forecasts of Natural Gas Use in Transportation Sector,” well, we’ve certainly talked about that.

"Outlook for Biogas Production," we haven't talked about that as much.

"Prices of Various Biofuels," no, we haven't talked much about that.

So on and so forth. So, recognizing the lateness of the hour, I would look to you and Malachi, whose wife we must have really influenced, to try to be, you know, condensed as best as possible, so we can save time for the other several items still on the agenda, and people who've spent a lot of time and effort to make presentations.

So, with that said, carry on.

MR. SCHREMP: Well, first of all, you weren't supposed to see that list and --

VICE CHAIRPERSON BOYD: I have my ways.

MR. SCHREMP: But since you have it, now, I will do my best to skip over items we've already covered.

Gordon Schremp, staff with the Energy Commission. I'll be going through our preliminary case results of the analysis performed by Malachi.

So, if there are any -- if there are any disagreements by what I'm showing, then please direct those questions at Malachi.

If you have any compliments for here, you know, you can give them directly to me.

(Laughter)

MR. SCHREMP: So, I just want to point out that this is basically a first-step analysis, an LCFS analysis that we've undertaken.

You know, Dwight's comments, well, I've yet to see, well, you're sort of going to see a little bit of that here.

And as Mike Waugh mentioned, you're going to see a little bit more when they release some of their draft information on compliance pathways.

So, this is a first step, but it is not a forecast. We've constructed these cases, I know there's a lot of detail in the draft staff report about sort of what our whole set of assumptions are for running each of these cases.

And, really, we're looking at feasibility based on fuel use, fuel availability, but having not mentioned credits, oh, by the way we are looking at, you know, credit generation and accounting for that in the balances from year to year.

So, does this have an economic overlay or constraint applied to it, which is more real world? No, not at this point, but that is some of the continuing we will -- and I'll be discussing that in just a little bit.

So, those of you who read through this portion of the report, you know there’s four cases and how they’ve been set up.

There is a change. We did talk about using lots biodiesel, B10, B20 after a certain period of time. We modified that assumption and reran these cases with a B5 max limit.

The purpose of doing that was to avoid getting to an area of having to do NOx mitigation. One of the potential NOx mitigation strategies above blends of B6 to B20 is to use a certain ratio of renewable diesel.

So, we didn’t actually go there. I mean you could do that, but because there’s a limited volume of renewable diesel, your opportunity to use even more biodiesel is somewhat constrained by that.

So, yeah, some additional credits could have been generated, but they’re rather modest, but we did do a B5 limit in all the cases.

And then, of course, no cost at this point but we will be doing that.

So, what I think all of you have to be asking yourselves and thinking about as we move through these cases is plausibility of the assumptions. People could characterize a lot of the assumptions in fuel supply availability as rather optimistic. Also, keep in mind some of the information I provided earlier about outlook for certain biofuels like, you know, ethanol from Brazil.

So, case one assumptions, some of the high points, no cellulosic fuel is used here, and we did use the lowest carbon intensity fuels available.

And thanks, again, to Mike Waugh and his staff for providing that information from the registered facilities. We couldn’t have done this analysis without them.

And oh, by the way, we have been working rather closely with technical staff at ARB and will continue to do so in discussing our assumptions, electricity forecast outlooks, use of FFV vehicles and E85. So, we’re trying to understand, you know, what our joint assumptions are and where there are differences, understand why there are differences. so we continue to work through that process.

So, electricity, Mike Waugh mentioned that not a lot of electricity in the first quarter, as you saw in that other category rather modest, and we would agree that it’s not a lot of people are quite aware that they could do this and register credits.

So, we have taken all of the electricity as credit, recognizing, ultimately, that some of it may not technically be eligible, or lags because they don't get into the system in time but for all intents and purposes light- and heavy-duty electricity demand forecast that Malachi have, both high and low, we took all of those credits, the same for natural gas and transportation.

So, this includes heavy-duty things like existing transit, or electrified rail like here in Sacramento, or Bay Area Rapid Transit. So, all that electricity we took as a credit.

So here are all of the fuels together, lots of colors, a kaleidoscope of colors, you'll see, because there's lot of different fuels.

And, actually, there are many more fuels, as Mike Waugh was pointing out, different pathways and different carbon intensities. And so this shows one stark result is Brazil ethanol, a lot of it. Well, that's more Brazilian ethanol that has almost been exported to the United States, ever, that would be at 2014, so that's a lot of Brazilian ethanol.

It shows in the gasoline portion there is some Midwest ethanol. This is some lower carbon intensity, not the traditional corn ethanol but some of the facilities, as Mike mentioned, more efficient process, lower 84, 85 grams.

And then we're seeing some sorghum ethanol, which certainly is a lower carbon intensity. No cellulosic at this point.

So, you'll notice that California ethanol always used, it's sort of a ground rule, we thought it's here, we better use it. People could argue that because it's slightly higher carbon intensity than some of the other ethanols that it would maybe go out of use and possibly be exported as possible.

But the ground rule was to use that in all the cases.

The diesel blends have a lot -- do have biodiesel, but it is B5, once again, and it's cherry-picking the lowest carbon intensity, which would be corn oil biodiesel, 5.9 grams, very, very attractive, but not a lot of it produced today and, arguably, likely quite expensive.

But the fact of the matter is we're looking at commercial available fuels or that could be available, reasonably, absent the economics, and to see what kind of compliance, how close you can get to compliance.

So this slide takes those credits, sums them in a stack bar arrangement, and then shows the deficit, as Mike was talking about, and how the deficit will grow. And this deficit is a generation of the gasoline and diesel, the petroleum portions for that particular year relative to that target, and this is all using high-demand forecast, our high-demand forecast. We, of course, have a low one so the numbers would be different, but I didn’t want to present 150 case results here. I thought you wouldn’t give me that kind of time.

So, as you can see there is compliance through 2015 or the first half of the program with the assumptions for these kinds of fuels, yet a deficit or, you know, a lack of adequate credits beyond that point.

So, what would it take? More credits, obviously. And in areas of using more volume for certain types of fuels because in the case one we limited it to what’s in the registrations. We know the volumes will go up, more people will register, but we did limit it to what’s in the registrations.

And just a point to make that since these cases are showing the results of selecting the lowest carbon intensity ethanols first, you won’t see any Midwest traditional corn ethanol in these results.

It doesn’t mean you can’t use it. Obviously, what Mike was presenting in the first quarter results are lots of Midwest corn ethanol. Yes, it can be used, but it won’t generate as much credit.

So, I think I skipped over one point is that although that line went -- you know, where the stacked credits were below the line in 2016, the use of built-up credits in advance of that carried compliance through for an additional three years.

Probably don't have to go into these concerns. Certainly, lots of Brazilian ethanol, very aggressive there. How realistic is that; you know, please give us comments.

And ethanol shuffling is something that we believe wouldn't be necessary to ensure because we don't think the incremental supply would be available, not in these volumes.

And biodiesel, even though it's a B5 limit, it's a lot of biodiesel. So, 50 percent of the record consumption in the United States, in California in 2012, so that's a lot, but there would need to be an adequate infrastructure in order to blend B5 at all the distribution terminals that had diesel. So, that's not in place yet.

As well on the first point, on the infrastructure, that the infrastructure capability in, say, the Houston ship channel has not yet been completed, so that's not in place yet, either.

So case two we said, well, let's get more low-carbon intensity material, so cellulosic we introduced. And as I mentioned, we're assuming our proportional share from RFS2, but not those aggressive, large cellulosic volume targets, a smaller amount, and I'll show you what that is a bit later.

So, we said we're taking our proportional share of that smaller. John Braeutigam mentioned suggesting using that EIA projections and we have those projections for the two scenarios that most closely match our high-demand and low-demand forecast, and we have those volumes available.

So, use that and also we're assuming that the lowest carbon intensity Brazilian ethanol is now available. And that's all the facilities that have cogeneration capabilities, about 600 million gallons of capacity, currently, and we expect more registered. We're assuming all of it goes to mechanized harvesting, which then drops their carbon intensity down to 58.2.

So now the results are lots of Brazilian ethanol, but you start to see the cellulosic fuels come in. And the cellulosic fuel is not just cellulosic ethanol, it's three types of cellulosic fuels; cellulosic ethanol, biomass to liquid, gasoline and biomass to liquid diesel. These are drop in fuels, these are very attractive fuels for LCFS utilization for two reasons.

One is they displace gasoline completely, the same energy content, and its associated carbon debt, and it brings in a fairly low CI and gets a lot of credit.

So, that’s a good material so we’re using, this is our proportional share of EIA’s forecast of those three types of fuels available, and lots of ethanol, still.

So, similar here, but now you’re starting to see some BTL gasoline in the yellow and some cellulosic ethanol in the dark purple being used more, as more becomes available in that EIA forecast.

And we’re also seeing some BTL diesel fuel in large volumes near the end, upwards of 300 million gallons by 2030, the end of our forecast period, and then it wants to use a lot of used cooking oil.

So, these are the most desirable blend stocks. And so now what happens? Well, more credits from these better fuels available in a little bit more quantity, and you have compliance through 2016 and the additional credits give you two more years, the same through 2018.

So, not enough credits, still, so you need more cellulosic fuel, more drop-in fuels and a little bit more of the other ones, so that’s what we increase in case three.

So, very heavy dependence on Brazilian ethanol, still, same concerns with biodiesel. However, cellulosic fuel in these volumes does raise some concerns and that's because it's nearly equal to the entire amount USDPA believes would be available next year in terms of capacity. And that, I should note, is the upper end of their estimate at this time.

Sometime in November, the range is 3.5 to 12.6 million gallons, they'll finalize the number for compliance next year. So that's -- so that would be a lot of cellulosic ethanol to use in California at the beginning of next year, so just with that caveat there.

So like I said on case three more, more low-carbon intensity material, so we say, okay, half of the cellulosic fuels that EIA says is available in the national supply, we'll use that.

And then we start looking at larger amounts of renewable diesel, significantly larger. And as we wrote in our report, you see these are some, you know, 50 percent of U.S. supply from that type of feedstock.

So, is that a lot? Yes, it is, but we want to -- we want to sort of test the sensitivity of how much more of certain types of fuels might be necessary to help achieve compliance.

So now we're seeing greater use of BTL material because we've significantly increased that about five times worth because we're ten percent of proportional share and some of these other fuels have increased because we've increased that proportion. So, gasoline, you don't, Brazilian ethanol, no Midwest. Lots of cellulosic ethanol and BTL gasoline, an awful lot, which gives you lots of credits.

And now we're seeing diesel go up. Now, I mentioned B5 is the limit, so you go, well, how can you have almost two billion in total? Well, because once again the BTL diesel fuel replaces carb diesel. So, it's not a biodiesel, it would not be a NOx issue requiring mitigation, that I know of.

And then we're increasing inedible tallow, which is a very good low CI material, by increasing that feedstock's availability.

So, where does that get you? Well, that gets you compliance through a longer period through 2017. And sort of a strange thing happens here, a period of you're out of compliance and then you can go back in.

Well, how can that happen is because of the greater and greater use of drop-in fuels, you get less deficits in light of redline declines, and more credits, a lot of the credits rise, so that's why you can go back into compliance.

So, you also build up excess credits and that can go through, carry you through to 2020, so that's almost, if we go back up there, that's not quite fully compliant, there's some space to still fill in. So, this is pretty close. But, certainly, we're making some -- we're making some assumptions about certain supply availability that are quite high as, I mean, you can read through this list.

But, certainly, the cellulosic fuels, 56 million gallons beginning next year, that's four and a half times greater than the maximum available.

So, is this a bit of a stretch? Likely on the cellulosic side, maybe some of the others not quite as much, but we want to look at what are some feasible pathways through the program, itself.

So, case four, I'll show these, I'll go through rather quickly. We were increasing the used cooking oil, which is a rather low carbon intensity. However, because of the B5 limit in the selection of more desirable -- or greater availability, lower CI material for diesel replacements, it really wasn't used.

So, the results of this case, and even increasing the Brazilian ethanol to a higher amount of the best type, immediately in 2011, it still didn't take that much more of it, and so the results of this case are essentially identical to the other and you really don't get much of a change.

So, that sensitivity is like, well, that doesn't really get you anywhere, so it's almost as if you could ignore the results of case four.

So, I'll just pass through the observations, the concerns would be the same of all the previous cases.

I've covered this ground, cellulosic availability, hmm, in those volumes -- in the downgraded volumes, yes, but in the higher amounts.

Here's what I've been talking about; we didn't use the redline for that cellulosic availability, Congress's vision, we used the stacked bars on the bottom. That's the U.S. availability, according to EIA, for cellulosic fuels, all three types.

So we used these, our proportional share of about ten percent, and then in the case three we used half of these volumes.

But as you can see, they almost pale in comparison to what Congress has suggested.

And, you know, in John Braeutigam's suggestion and Commissioner Peterman's direction to look at a sensitivity for this, of changing that, yes, if we were to use the cellulosic volumes and replace the ones in the original table, the amount of E85 would go down and it would change -- it would change these results because we're looking for ethanol in certain flavors to meet that ethanol target, which would now be lower.

So, it's possible that the deficits will be a bit higher and the credits may be a little bit less once we do that for LCFS analysis, but RFS2, post-processing, the results will be less E85 and less infrastructure impact.

So, but we -- but that's, I think, good direction and it would be very good to look at that and see how it all plays out.

So, these are some supply assumptions on some of the best low-carbon intensity and, hopefully, we can get some feedback from the forum on the 22nd of September, because this is a lot of -- corn oil, certainly, in the ag community, how reasonable is this? Could all of it be moved into a transportation fuel use or is that unrealistic?

What are the upper limits of inedible tallow and used cooking oil, how really far could you go because of this inverse relationship, collecting smaller and smaller quantities at higher and higher cost.

So, we're looking for feedback in your comments about these assumptions. It's very important that you sort of -- you weigh in, most importantly, on the expense of the fuels. Why? This is the next set of analysis we intend to run on the LCFS, overlay an incremental cost constraint.

So, how do you do that? We're looking at three mechanisms, near-term pricing information, Brazilian ethanol's a good example, good prices on that. We can calculate what the delivered price is to California, we have lots of data on that.

Federal RIN, renewable identification number values, lots of information on that. How are we reading that? Are we reading that properly? What does $1.30 a gallon cellulosic RIN mean? Is that the incremental price it should be relative to corn ethanol?

These are good questions we want to properly understand what we're looking at to properly use these near-term historical references as a starting place to run some cost sensitivities.

A final point is we expect low-carbon fuels, like the Federal RFS fuels, to have credit trading activity. Once the platform is up and running, we think that will start to give us information on what the values should be.

Right now there's very little information. The Oil Price Informational Service does show two different types of corn ethanol, and if you calculate the carbon intensity difference, it works out to be .2 cents per gram.

So, we’re going to start with using that as an adder for some of these fuels, but it’s very modest. I mean, I’ll just give you a couple quick examples, that best corn oil biodiesel would, probably, because of this kind of low amount of premium, about 15 cents a gallon adder.

And something like the best Brazilian ethanol, it would be about 6 cents a gallon and cellulosic about 10 cents a gallon.

Certainly, when we see RINs for cellulosic about $1.20, that these values might be low, this is an early type of reporting in the system and until the credit trading platform gets up and running for LCFS credits, we won’t really know, but we expect these to go higher.

So, we’re looking at a sensitivity over the higher range, but we just don’t know how much higher we should go and your input would be appreciated.

So, here are the prices, they’re pretty expensive for Brazilian ethanol because of the tightness in the market I explained, and this can be a cyclic thing that can occur or it could be something that’s more persistent and could get a little bit worse. We don’t know, but history will tell.

Biodiesel is very expensive, $3.00, I gave you some prices, about $6.00 a gallon now. That’s certainly a lot more than the $3.00 wholesale prices that they'll sell for diesel. So, it is really expensive at this time, which is why some of the companies, a lot of them are having challenges getting enough to meet the Federal standard.

So, should -- and that's just regular old soy biodiesel, easy to make, lots of it around, there's lots of capacity for that. How about difficult, more expensive feedstock? Should it be the same, should there be more of a premium? Don't know the answer to that, but we're looking for some input.

The same with cellulosic and these other -- these other measures, what are some appropriate metrics to have a cost, what sources of information should we use and what rationale?

So, we will -- we'll going to do this. We're going to be looking at this overlay of a cost constraint. We want to be clear that if there was no LCFS program there would be a use of cellulosic fuels in this State, as well as advanced, more expensive things like Brazilian sugarcane, and we believe all of that has an incremental cost, so that could occur anyway.

So, our comparative is not going to be just where we are now then, oh, you know, here's all the incremental costs and it's all the LCFS. No, it's a portion of this is going to be RFS2 obligations, our proportional share and that will be the sort of the starting point in the comparative. And then how much more fuels would we use that would be different than the RFS2 obligations, and what would those incremental costs be?

So that would be sort of a part of the results of the analysis.

And I think we've covered this and we've had a suggestion on maybe what to do with the proportional, so I think it's good to take a look at the EIAs forecast and leaving -- and leaving the other advanced alone and then lowering the total.

so, I think that's a good suggestion to take a look at and see how that changes the results of both our post-process forecast with RFS2 and the LCFS analysis.

Final slide, I believe, or close to that, is I think Mike Waugh mentioned, regional and national. So, just briefly, pointing out the obvious that as you saw from these case results, using a whole variety of fuels and all these electricity and natural gas credits still, you know, there's some challenges here and some of them can be significant.

And so that's California using 50 percent of the cellulosic field or a whole bunch of Brazilian ethanol that has ever been imported to the United States and, in some cases, has ever been exported to the world by Brazil. So, that’s a lot of fuel.

So if you put these other areas, they’re looking at the LCFS in context of their fuel that they consume, compared to California, you see things like gasoline, 3.7 times greater; diesel, 7.2 times greater.

so, these are the regions, if they were to go and pursue LCFS-like regulations. That competition for those kinds of fuels would be also with these other parties then. And so that -- I mean that will likely have an impact on the marketing floating price of those more desirable fuels.

So, I just wanted to point that out, that that would certainly be a concern, a selfish concern, if you will, from a California perspective of other areas going and competing for some of the fuels that obligated parties here will need.

So, I think -- I think that’s it for now.

VICE CHAIRPERSON BOYD: Very good, Gordon. No question here. Question from the audience? There’s one hand, Jim Lyons is next. Gina, you too? Okay.

MR. BRAEUTIGAM: Jon Braeutigam, Valero. Three quick points. When I -- the suggestion I made, Gordon, was when you switched to the cellulosic for a given year if the drop from the original Congress amount is X, that you also reduce not just the total, but also the total advance requirement also by X.

Okay, because if you don't, you're just not going to have all this other total advance.

You may want to look at how high you're going on drop-in renewable diesel to have TC labeling regulations, treat renewable diesel the same as biodiesel. If you have more than five percent renewable diesel in, you have to label the pumps, which means it's really going to -- if you could put five percent renewable diesel in upstream at the head of the pipeline and people could still use B5 blend at the rack and not have to label the pumps.

But if either one of those goes over five or if the sum of the two goes over five -- goes over ten, excuse me, I can't even do simple math anymore, then you would have to label the pumps, which makes it a -- almost forces having to do the renewable downstream which, once again, you have the infrastructure issue.

We don't see cellulosic available until maybe late 2012, probably 2013 and that's at a plant that's announced in Iowa. I would caution maybe watching that.

The EPA's gotten the avails wrong two years in a row, and with what they're proposing for next year, I think they’re going for, what we call in hockey, a hat trick, you know, having three years straight be in way too low.

As far as your costs, my advice would be figure out what is the incremental, low CI biofuel coming in, in a year to set the compliance? What’s it’s incremental cost like, if it’s an early year, it’s sugarcane ethanol, and the sugarcane ethanol is $1.50 out of the market, so you’re paying $1.50 a gallon for that sugarcane ethanol, because of its low CI. Look at that CI versus the standard, divide the $1.50 by the delta CI numbers.

That should set the market clearing price for all CI numbers, including corn ethanol, at whatever that cent per CI number is, which I think is around six cents or something, if you’re at about the $1.50 level which, obviously, six cents versus .2 adds an awful lot more costs to the program.

Thank you.

MS. GREY: Gina Grey, WSPA. First of all just wanted to just say it’s kind of unfortunate that this presentation didn’t happen this morning, and I know we’re short on time so I really need to truncate my comments severely this afternoon.

We also have --

COMMISSIONER PETERMAN: Don't forget to submit them written, as well.

MS. GREY: We will. Thank you.

We also have two contractors that we asked to come here today to speak, one on this subject and then the next one on the high-carbon intensity crude oil, so I'd wanted to give them time to talk as well.

But first of all just wanted to say WSPA really appreciates the fact that the Commission took this issue on. We did request that in one of our earlier sets of comments because we felt this was a very significant part of the overall forecast for what the Commission feels is going to be happening in terms of energy supply.

Recognizing that the LCFS was constructed by California Air Resources Board, another sister State agency, but you folks definitely have a very unique and important perspective in the State, which is to look at, you know, reliable, secure energy supplies for the State, make sure that nothing's going to occur that would perhaps impede sufficient transportation fuel supplies, and look at things such as costs, et cetera.

So, just a since thank you that you actually did take this on and are doing some of these compliance curve analyses.

I think one of the things that we also asked for earlier on was just a look back at what ARB had proposed as possible compliance scenarios in the 2009 time frame, and would be interested in staff's comment as to just why those were not done. If they were felt to be unrealistic at this point in time, we'd be interested in hearing that, as to why these scenarios were selected, et cetera.

I think WSPA, when we participated in the advisory panel, we did show a compliance curve that showed some possible issues cropping up in the 2013-2014 time frame in running through all these low-curve intensity fuels, as to whether or not they're even going to be available, let alone what the costs might be.

So, I'm interested in what Gordon has been talking about today in terms of sort of the fact that what has been done here are very optimistic assumptions and inputs in terms of availability of these certain types of low-CI fuels, in terms of costs, et cetera, et cetera.

So, we will certainly be providing Gordon with some comments on the assumptions that went into these and would be interested in perhaps configuring what staff feel is maybe a more realistic scenario as well, not so optimistic.

But, certainly, if we’re looking at the 2016 of ’17 time frame, even, and saying that these compliance scenarios appear to be showing potential problems with compliance during that time frame, not the 2020 time frame, I think that’s cause for pause and consideration of what are these scenarios telling us.

And one, I think, statement that was on page 128, and is actually under the National LCFS portion of the document, but this, I think, kind of summarizes what people should be thinking about here even, you know, regardless of all the scenarios and everything else. But, you know, the basic statement that “the calculated volumes required by California-obligated parties either approach or nearly approach the entire national supply of renewable fuels with low enough carbon intensity.” That’s let alone, you know, if there’s any national LCFS programs, or state programs, et cetera, just California, alone, in theory looks like it needs all of those very low CI fuels.

So, that fact, alone, which staff has put on a piece of paper here I think, should give pause for everyone that’s considering what’s going to be going on with the LCFS program, let alone, as I mentioned, any cost aspects or anything else.

So, you know, we will be supplying detailed comments and when folks feel it’s ready, we do have a contractor here to give some more specific comments.

MR. SCHREMP: And I’ll just, your first question about why didn’t we look at those -- I guess I don’t want to mischaracterize Mike but, you know, the scenarios that -- you know, from 2009. It’s my understanding that Mike’s group is reexamining those, those scenarios, and so we knew that was going to be happening. We didn’t want to duplicate, replicate that kind of work and we wanted to go from an approach of using our most recent forecast outputs, adjusted for RFS2 proportional share compliance, and then examine what fuels would be necessary and in what combination to try to achieve compliance with the LCFS.

So, our approach was a lot different and we didn’t want to be duplicative of what Mike’s group was doing.

And so their work hasn’t come out, yet, so I think your answer to that question is you will soon see this analysis.

Did you want to add anything else, Mike?

MR. WAUGH: Yeah, Mike Waugh with ARB, again. Regarding the 2009 illustrative compliance scenarios, I mean we stated clearly in our staff report that the LCFS was relying on a successful implementation of RFS2.

And I think the challenge that we have and that the CEC staff, we're all looking at the same thing, which is cellulosic ethanol, which was supposed to be in the marketplace in sufficient volumes, and it's not there. And so we're going back to figure out at this point, as required by our regulation, and through the help of the advisory panel that we're looking to see, okay, without the volumes of cellulosic ethanol that we thought would be there two years ago, how can regulated parties comply with the LCFS.

So, again, we're trying to align our assumptions with CEC staff assumptions and we're all looking at this at the same time.

So, that's the big difference is that the cellulosic ethanol is not there. We said that we were relying on RFS2 to be successful, for the LCFS to be successful as well.

VICE CHAIRPERSON BOYD: Thanks, Mike. I empathize with your dilemma. It suddenly dawned on me your cellulosic ethanol was my advanced batteries of the nineties.

Is Jim rising to give his presentation or is Jim rising with a presentation? You're next on the agenda.

MR. LYONS: I can do either. Let me just add a couple of quick comments and then I'll give my presentation.

First, I understand your point about costs and attributing the RFS2 program its fair share of costs, but I think you also need to present the total costs to get to the total goal RFS2 plus LCFS.

As you pointed out, RFS2 can be modified and if that program's modified, LCFS cannot, and so you'd still be stuck with the total cost, but it would just be apportioned differently.

And then the second thing is with regard to the plausibility of assumptions, I think you need some sort of a rating scale, because your presentation convinced me today that compliance isn't feasible, but I could see absent some sort of a rating scale that it might convince somebody else otherwise. So, you know, like very likely, highly unlikely, some of them might require a miracle in order to be plausible, those types of designations so people can kind of sort through that.

And I would second Gene in his recommendation for at least one sensitivity case with your most likely set of assumptions to show what happens in that case.

VICE CHAIRPERSON BOYD: Does anyone else have any questions or while Jim's still standing he can -- I've been trampling on people on the phone, giving deference to those people who are toughing it out with us here.

All right. Would everybody like a 30-second stretch break, while Jim is getting ready? Just stand up, breath deep, massage the parts of your body that hurt.

(Break)

Okay, hate to break up the joy in the audience but -- this might be to your benefit, Jim, we've got some blood flowing.

MR. LYONS: I think you're right, thank you.

I guess I'll go ahead and start here.

VICE CHAIRPERSON BOYD: All right, Mr. Lyons is going to begin.

MR. LYONS: I'm Jim Lyons with Sierra Research, I'm here today on behalf of the Western States Petroleum Association, presenting some observations from a review we're doing of the CEC's Transportation Energy forecasts.

I'm going to give some initial observations. I know this is a work in progress and a lot of what I've heard today is already leading me to the understanding that a lot of my concerns are going to be addressed as the report goes towards finalization.

One thing in the current report, the data is kind of presented in a shotgun fashion. There are very interesting pieces of information that are kind of strewn all over the document and you have to kind of go get them and bring them back together in order to do any kind of meaningful analysis and so, hopefully, that will be something that's tightened up as the report comes together.

One point that was just discussed is that the IEPR assumptions differ considerably from the CARB assumptions in 2009, particularly with regard to the electric fuel cell vehicle sales.

And I think as Mike Waugh just pointed out, there's a large difference in the assumptions regarding cellulosic and advanced -- other types of advanced biofuels on the gasoline side.

I think it's very important that one common set of assumptions come together and get used by both agencies so that everyone is talking off the same page, and all the comparisons are apples to apples.

The LCFS analysis not only needs to consider the fuel cost, in my mind, but should also include the vehicle costs for electric and hybrid vehicles. You can say those belong in another program, but I think an informed an analysis of the overall impact on the public would also at least identify those costs and not just pretend that they're zero for purposes of a fuel regulation.

And as other people have already pointed out, you think that it’s a very questionable assumption to have California getting assumed to have access to almost all of the nationwide supply of low-carbon intensity fuels.

This is a very busy slide, it’s from CalEPA. It’s just here to highlight the importance of considering the practical limitations and barriers to the introduction of different kinds of fuels into the transportation fuel marketplace.

When you look across here there is, you know, E15, which isn’t a player in California at the moment and several years would be required, by my estimate, to get all of the steps to get that fuel into the marketplace.

So, I just want to make sure that any analysis of what could happen in California reflects the practical reality of what’s currently allowed and factors in the lead time associated with what would have to happen in order to get it here.

I like kind of looking at this on a fuel-by-fuel basis. I’m going to start with ethanol at the E10 level. The forecast demand in 2020, and I picked that year because that’s the current culmination of the LCFS ramp-in, is about 1.3 to 1.45 billion gallons. As Gordon's already illustrated, that's a lot more than Brazil plans to export to the U.S., based on figure 512 in the current IEPR.

And I would also note that that export forecast is down from the export forecast that was in the 2009 IEPR, so that kind of bears out the trend that Gordon presented, that Brazilian imports are going down.

And even the EIA forecasts appear to be fairly optimistic because they've got two billion gallons in imported ethanol for 2020.

And then the cellulosic ethanol forecast is, as was pointed out, much less than the RFS2 requirement.

I'm going to talk a little bit about price. These are some of the different price numbers or cost numbers that are in the current version of the IEPR that, you know, range from two cents for low-carbon intensity fuel to $1.75 per gallon for Brazilian ethanol. There's really kind of no value that's been selected.

I saw the $1.50 today, that appears to be a fairly reasonable number.

Anyway, my point is that if you use some of these numbers you can get an incremental cost for ethanol at about $1.50 to -- or $1.75 to as much as $2.5

billion per year. That's a big cost number and that's just for the E10 portion of the fuel market. And those kind of bottom line cost numbers, it sounds like they're coming, but I would strongly urge you to get those into the report and have them featured prominently.

Impacts of infrastructure limits, it goes back to the plausibility of assumptions and the costs, and then it's already been talked about today on ethanol fuel shuffling, so I won't belabor that any further.

The current E85 forecast is about the same as for gas and about another 1.3 billion gallons. The current assumption that each E85 FFV uses about 800 gallons of E85 a year. For a 2010 Flex Fuel Malibu, that's about 12,000 miles of operation or pretty much all of its annual mileage accumulation. So, that's a smaller vehicle, with higher fuel economy and it might be 50 or 75 percent for some of the other numbers, but you might want to go back and check and see what you're using for E85 fuel economy.

Again, since it's about the same volume, we've got potentially about the same cost if this is going to be low-carbon intensity fuel. Obviously, if it is, that has LCFS ramifications, but it could be as much as another two and a half billion dollars.

Straight out of the IEPR is the infrastructure cost which is, over a ten-year period, about one to 21 billion. It would probably be good if we could narrow that range down a bit because that’s a pretty broad range.

And I’d also note that the assumed number of FFVs in the current version of the IEPR is much less than it was in the previous version of the IEPR. I don’t know if that’s just because of economics or better date on what manufacturers are actually producing, but I think that fact should be acknowledged.

Talking about FFVs, this was alluded to earlier, I’ve got a graph here that shows the available CAFE credits going out through 2014 and then starting to decline.

And then the IEPR forecasts the continued growth of FFVs in the California vehicle population.

As I can see it right now, this is about the only incentive to actually produce an FFV. Manufacturers might do so for other reasons, but it’s not clear that they will.

And I’d also like to note, in the bullet point at the top, that the IEPR currently assumes about 166,000 new FFVs a year in California over this period, and when I look at the 2009 IEPR, the total then was about 380,000. Look at this one and it’s 443. So, in two years we’ve got about 60,000, and so we’re nowhere near 166,000 per year based on that data.

A similar kind of slide for biodiesel, at B5 it’s about 200 million gallons, as Gordon pointed out. It goes up if you assume higher biodiesel levels. And the cost infrastructure and warranty issues have already been pointed out, so I won’t need to talk about those further.

Drop-in fuels, if you look at the biomass to liquid and the renewable gasoline diesel in EIA, you get about 800 million gallons, .8 billion, as the IEPR points out. Only renewable diesel is currently commercially available and I think that has implications for what you can do for forecasting that.

There’s a statement that it’s more costly, but there’s no quantification of what a likely price increment is. You just asked for information on that and so that obviously explains it.

But I think you really need to do a forecast for drop-in fuels for California. It looks like it’s kind of coming out of your LCFS work in terms of what would be required.

But again, in kind of at least semi-quantitatively addressing the plausibility of some of the assumptions, I think you need to forecast what you think is likely to get here.

Natural gas and biomethane it’s -- I guess Tim Carmichael’s gone, but it’s limited by the small natural gas vehicle population, which isn’t forecast to grow substantially. If it does, then obviously the potential for biomethane could go up.

The refueling infrastructure is limited, it’s mainly for centrally-fueled fleets, which is why you don’t see it so much in the light-duty market. And it wasn’t clear from Tim’s conversation today if these private companies were continuing to invest in different types of centrally-fueled fleets or a real broader application for heavy-duty vehicles.

The other thing to consider here is CARB has got fuel specifications for natural gas that’s used in vehicular applications. It’s not clear to me that biomethane meets those fuel specifications.

I guess if you blend it into the natural gas pool and dilute it enough, then maybe it’s not an issue, but it’s certainly a factor that needs to be considered if you’re going to assume that biomethane is going to be used as a transportation fuel in large amounts.

Onto electricity; we’ve now got about twice as many plug-in hybrid vehicles forecast as back in 2009. And I think there’s a typo or something in the electricity demand because it was 500 gigawatt hours, about 150 million gasoline gallon equivalents in the 2009 IEPR and it's down to 700 or about 21 million gasoline gallon, equivalent gallons -- gasoline gallon equivalents in the current one, so someone should check into that.

The electric vehicles, you assume, are mainly plug-in hybrid electric vehicles. The CARB assumptions assume far more straight battery electric vehicles. That's got some fairly significant vehicle cost implications.

Your assumed increase in PHEV sales rates is far higher than the assumed increase in sales rates for flexible-fueled vehicles. If we're having that much trouble getting the flexible-fueled vehicles into the market, which are functionally equivalent to gasoline in conventional vehicles, these ones have a price increment and it's not clear that the consumers are going to accept those, in those volumes.

If you take a fairly conservative cost estimate that came out of a 2009 car publication, of about $7,000 a vehicle for a PHEV, and you've got 3 million of them, then that's an incremental vehicle cost of $21 billion, which is a fairly significant amount of money. And, again, I think it's something that needs to be presented in the context of all of these LCFS and IEPR reviews to let people know that, yeah, you can save money on the operation of these vehicles, but there is a substantial cost and this is what it is.

If you look at the recharging infrastructure and assume $1,000 per vehicle on average, including public and other kinds of charging, that's another $3 billion to get 3 million vehicles into the market.

And at some point there should be a quantification about the fuel savings costs, as was suggested earlier today, but you also should probably look at the battery replacement costs, if you're going to assume that there is any battery replacement going on because that will have to be amortized at some point as well.

These are the most recent CARB sales forecasts I've seen for different kinds of vehicles. You see conventional vehicles dropping rapidly. Here's a couple of, I'll call them blips, for hybrids and plug-in hybrid electric vehicles and then a massive increase in fuel cell vehicle and battery electric vehicle sales.

If we look at 2020 or 2030, in the chart on the right you'll see that there's a lot more fuel cell and battery electric vehicles in play, than plug-in hybrids. That's kind of the opposite of what the CEC IEPR report -- excuse me -- report is indicating. So, again, there's a need to reconcile these different assumptions and make sure that when we're talking about what's going to happen as a result of the ZEV mandate, or the CARB regulations and their impacts on transportation fuels, that everybody closes the loop so that we don't have one set of numbers being used in one regulatory vehicle, and a different set of numbers being used in a different regulatory venue.

This just kind of shows it a different way. By the time you get to 2025 you've got lots and lots of hydrogen fuel cell vehicles and battery electrics in the CARB forecast, that aren't in the CEC forecast.

And as for hydrogen, as has already been pointed out, there's no demand forecast, there's no assessment of the required fueling infrastructure.

One kind of key point is if you look at the carbon intensity for hydrogen, even after you apply the EERs and the LCFS regulation, it's not real good. And the prices that you've got in this report don't, you know, reflect biomethane which is referenced as a way to lower the carbon intensity of hydrogen.

And, again, the assumption of a small fuel cell vehicle population is at odds with what CARB is saying in the zero emission vehicle rulemaking.

On the conclusions, as I've pointed out a couple of times, we need consistent assumptions, we need reasonable assumptions regarding the amount of low-carbon intensity biofuels that can show up in California relative to the nationwide production values.

Again, the cost of the vehicles, the fuels and the fueling infrastructure needs to be clearly laid out so that the total cost of the programs can be assessed.

And this goes back to the shotgun of data comment I made at the beginning, it would be good to have a very clear, concise analytical summary that shows these total costs and impacts, and gives kind of a more forceful assessment of what's likely to happen in the State as a result of these regulations.

I'll take any questions anyone might have and, again, this work is being funded by WSPA.

VICE CHAIRPERSON BOYD: I don't think I have a question, Jim, just a reaction to the desire for consistent -- consistency between agencies, and that is always the utopian desire.

And as you've heard from the very cooperative relationships that exist, I'm sure staffs are trying to reconcile numbers.

But I have lived through periods of time when you just can't reconcile, you have different opinions.

And that certainly has been true with plug-in hybrids all along. I mean it went from zero interest in one area to kind of interest in another, and I think that was -- that's proven to be -- you know, one agency seemed to have been a little more correct than the other.

The same holds true for the role of natural gas, there were some very significant differences of opinion on that subject for a few years and it just appears that natural gas has taken on a greater role, as envisioned by this Agency, just because of all kinds of facts that have happened. Some couldn't even be seen, like I don't think we envisioned all the shale gas that was around, but et cetera, et cetera.

So, good point, I mean and everybody would hope you could do that, and I'm sure the staffs are trying. Can't always guarantee that.

COMMISSIONER PETERMAN: And I'll just also add there that I think what we're striving to do is have a continued greater transparency, if consistency's not possible. So, if there are particular parts in the document where you think the assumptions are not clear, or it could be laid out in a more clear way, that would be useful to have comment on.

And also, I'll note that with 250 plus pages, we appreciate stakeholders, like yourself, doing a careful read and pointing out where you see inconsistencies or have questions because that's how you check it. So, thanks.

MR. LYONS: Thank you. And if I could respond just on the assumptions real quick, I understand it's impossible to always get everybody making the same assumptions. however, it's important that people understand where there's different assumptions, because otherwise you'll get into this shell game where you'll take some of the costs for a program and put them one place, and ignore them in another place.

VICE CHAIRPERSON BOYD: Certainly, internal consistency is uppermost.

MR. LYONS: Thank you.

VICE CHAIRPERSON BOYD: Did anybody in the audience have any questions of Jim Lyons and his presentation?

You have a question?

MS. TUTT: Yes, thank you. This is Eileen Tutt with the Cal ETC and I just want to point out that I think the one thing we know about forecasts is they're not going to be right and they will be different next year than they are this year.

So I understand the particular Vice Chair Boyd's comment on that in terms of I think it's okay to have differences, but I also agree with Jim that you have to understand why there are differences, and I had similar questions early on.

And that will be helpful in particular with agencies that are your sister agencies. So, it's good for us to understand on the outside.

And I do -- I also just want to say, because I had another meeting I had to go to while the LCFS discussion was going on, so I'm going to loop back with staff and just warn you that I have an interest and I just want to make a few comments on that, but I'm not going to use my time now to do that.

I just -- I do want to point out that I actually -- my point for this particular section is that forecasts, everybody -- I think it is appropriate that they're not identical, so I'm okay with that, I just want to know what the differences are and why they're different.

VICE CHAIRPERSON BOYD: Thank you, Eileen, and thank you for -- and, you know, very definitely come work with the staff, I'm sure they're very open to hearing your comments. And the tired audience here is grateful for the fact that you're going to pursue that avenue.

Any other questions, folks? Hearing none, I guess we move on, on the agenda.

MR. EGGERS: Good afternoon, Commissioners. Ryan Eggers, Fuels and Transportation Division; I'll be giving staff's presentation on Crude Oil Import -- on the Crude Oil Import and Infrastructure Forecast for California.

Shown here is the United States crude oil production from 1981 to 2010. As you can see, crude oil production here in the United States has been on the decline.

In 2009 and 2010 there was an uptick in United States crude oil production, this was mainly from increased production in the Gulf Coast states.

Also displayed here is California's share of total U.S. crude oil production.

Looking a little bit closer at California crude oil production, as you can see by the green area on this particular chart, California has gotten most of its crude oil production from onshore sources, which have been in decline since 1985.

And when we look at a more longer-term view of crude oil production here in California, from that peak in 1985, of 424 million barrels, crude oil production has been declining fairly steadily and fairly significantly, to the point that current crude oil production is at roughly the same level as it was in the 1940s.

So here are some of the production totals in 2010 for the world, U.S. and California. After looking at some of these trends, staff believes that crude oil production in both the U.S. and California will continue to decline barring any new production techniques that do come out into the market and change that dynamic.

When looking at California crude oil imports, here from 1982 to 2010, we see from the early eighties into the mid-nineties that Alaska was the most imported crude oil into California.

At about the turn of the century foreign crude oil became a more prominent imported crude oil here into California and is now the most imported crude oil into California.

Looking at some of these trends, from 2000 to 2010 total crude oil imports have increased 13 percent. Alaska’s share of that crude oil imports has declined 47 percent.

To make up for that decline in Alaskan crude oil imports, foreign crude oil imports have substituted for that and it’s increased roughly 71 percent from 2000 to 2010.

So, in order for staff to make its crude oil import forecast, staff first has to make two other forecasts in order to get to that import forecast and, thus, the infrastructure requirements from that forecast.

The first forecast would be the refinery distillation capacity forecast and then the second one would be a decline rate for California crude oil production.

In the case of the refining capacity forecast, staff looked at two different utilization rates for California refineries. The first being roughly a 90 percent utilization rate, which was an average from 2000 to 2010.

In the case of the lower utilization rate of 87.6 percent, the last four years' average was used. As part of this lower utilization rate, I would also like to note that staff assumes that the economics of this lower utilization rate will likely force some refinery assets to possibly close.

In order to forecast the closures of those refinery assets staff, as part of this utilization rate, has also forecasted about a half-percent decline in refinery capacity as part of that forecast.

Looking at crude oil production, staff chose two different decline rates for California crude oil production decline. The first lower decline rate was a decline rate of 2.2 percent, which was the decline of crude oil production from 2009 to 2010.

In the case of the higher production decline rate, a 3.1, 3.2 percent per year decline rate was used, which was the average decline of California production from 2000 to 2010.

When combining these two assumptions, actually four assumptions, in the case of the high forecast that 90 percent utilization rate was combined with the higher decline rate of California production and, thus, a high forecast of crude oil imports was created that has crude oil imports increasing from 376 million barrels in 2010 to roughly 480 million barrels in 2030.

In the case of the low case, with that decline in refining capacity and a lower decline rate or production, crude oil imports go from 376 million barrels in 2010 to roughly 398 million barrels in 2030.

This slide shows how some of these assumptions were combined in order to create the high and low forecasts, which I've already gone over.

Once we have the crude oil import forecast settled on, staff can then make assessments on how many additional tanker visits will be needed in order to supply this additional crude oil import.

Staff is projecting an additional 12 to 149 additional tanker visits by 2030. The wide variation in these two forecasts has to do with the tanker capacity differences between VLCC and Aframax. The VLCC total was applied to the lower forecast, creating that 12 additional incremental visits, while the Aframax cargo size was applied to the higher forecast in order to create the 149 additional tanker visits assessment.

In looking at crude oil storage capacity, two different cycling rates were used in order to create the additional storage tank capacity requirements in requirement forecasts for staff.

In 2030, additional storage for California has been forecasted to increase to 1 to 8.6 million barrels by 2030. Staff estimates about 60 percent of this storage will need to occur in Southern California.

But in the low-case projection there is currently enough existing infrastructure to accommodate this additional capacity need, barring any foreclosures of those facilities, of course.

There are some uncertainties in our forecast. The first would be technology advancements in the production of crude oil, which could change and thus, California might actually have more crude oil than it normally would have.

An example of this would be California shale oil reserves. These are currently estimated by the EIA at about 15.42 billion gallons. Actually, I believe that’s 14.2 billion barrels. I apologize for that.

Another thing that could affect our forecast would be new import facilities wouldn’t have been completed in time to adequately supply this crude oil to California, thus throttling the amount of imports that could come into California.

Another possible change in our crude oil import forecast could be the opening up of drilling off the shore of California.

The DOE currently estimates about 5.8 to 15.8 billion barrels of undiscovered, technical recovery resources out there off the shore of California, in Federal waters.

The Mineral Management Services estimates that under the current price of crude oil, today, that these crude oil reserves would be technically recoverable.

Some restraints in moving forward with this production would be, of course, the crude oil spill that’s recently happened in the Gulf of Mexico, and also new infrastructure requirements would be needed to develop these areas.

Looking at that no more --

VICE CHAIRPERSON BOYD: Excuse me, is that to say this is not obtainable off of existing platforms, it would take new platforms?

MR. EGGERS: A lot of those existing platforms would likely have to be updated and there would be some additional platforms that would have to be built.

VICE CHAIRPERSON BOYD: Good luck.

MR. EGGERS: Well, say California was, I guess, lucky, the DOE is estimating if this was actually happened, a no-moratorium drilling scenario, that this oil could be gotten at as soon as 2015.

A part of this forecast, DOE is also expecting that 74 percent of this incremental production would come off the shore of California.

And if this production was actually coming online, this would reduce the amount of imports under both the high and low forecasts to less than totals of 2011.

That concludes my presentation, I would like to take any questions or comments from the Commissioners and Advisors, first.

VICE CHAIRPERSON BOYD: I have no questions. I said my thing.

COMMISSIONER PETERMAN: I have no questions but thank you for your presentation and your swift movement through it.

MR. EGGERS: Questions from stakeholders?

VICE CHAIRPERSON BOYD: Here comes Dave.

MR. HACKETT: Hi, I'm Dave Hackett with Stillwater Associates. Stillwater's an energy consulting company headquartered in Irvine and our practice areas include policy, technology development and mergers and acquisitions in this space.

And I had a couple of things that are sort of a wide range of comments, so let me sneak them in here. I came up because I really wanted to hear the low-carbon fuel standard forecast. I think it's a signal event, it's the first time we've seen the government put out the balanced. And so I appreciate that and I'm looking forward to studying it and understanding them better, but thank you for that.

I think you guys wrote a comprehensive report. I read the whole thing. I think -- or my issues here, I applaud your continued emphasis on the need for logistics facilities, not only for petroleum, but for renewables.

I think the issue with the low-carbon fuel standard is primarily the assumption around the fact that cellulosic ethanol would be available and it's not, and so the program needs to be adjusted for that lack of technology development.

In your plan you've got a lot of biodiesel, but I don't think there's enough vegetable oil supply to have, maintain.

There's also an assumption that the Europeans could supply biodiesel to California. You need to look at the economics of that, but they wouldn't likely support biodiesel to California.

And the same, look at the economics of the cost to produce a renewable diesel in jet, they're not cheap.

You mentioned a potential for a refinery to shut down. Well, maybe, but depending on world markets, that excess refining capacity could be devoted to exports.

I will also say that we like compressed natural gas, primarily because of the big spread between natural gas and petroleum primarily as a function of drilling technology.

I learned today that electricity is cheap, a lot cheaper than petroleum, but I also don't think that they're including the taxes when they do that, do those economics. And what is there, 75 cents a gallon taxes, today, that I don't think goes on electricity.

And then, finally, I think that there are two crude oil projects, crude oil internal projects in

Southern California, probably enough demand for one of them. So it's going to be interesting to see, you know how all that sorts out. Thank you.

MR. EGGERS: Thank you for your comments.

Any other comments from stakeholders? Then I will turn my presentation over to Gordon.

VICE CHAIRPERSON BOYD: When you guys said 9:00 to 5:00, you meant it, didn't you? And on a Friday, nonetheless.

MR. SCHREMP: Yeah, we're not in Australia, okay, we work here.

(Laughter)

MR. SCHREMP: No disrespect to the subcontinent.

Gordon Schremp of the California Energy Commission. Is this the last scheduled one, am I it?

VICE CHAIRPERSON BOYD: No.

MR. KIM: No.

VICE CHAIRPERSON BOYD: We've got --

MR. SCHREMP: Oh, that's right. Sorry, Skip. Oh, there might be some comments. Okay.

So, this is, as Mike Waugh mentioned earlier, there is a high-carbon intensity crude oil element of the low-carbon fuel standard. We'll be talking about some of the work we've done.

He's already stated, you know, sort of the purpose of that, I won’t cover that again.

Staff was most interested in the potential impact on the availability of crude oil supply, so we worked, did a lot of work on looking at crude oil types, we’ll call them marketable crude oil names, or MCONs. We didn’t make that “C” silent, like they did for HCICO, so MCONs, and we looked at almost 250 of them.

And the purpose was to see what’s available around the world and what categories they might fall into.

So, potential HCICOs and I’ll stress the word potential, that’s why it’s in bold and red, in part, and that’s because I think, as Mike briefly mentioned, there is a process to go by, that parties can go through to submit additional information to say, no, my -- this crude oil that I would like to purchase is actually not a high-carbon intensity crude oil.

So, there is a process to go through, you know, how difficult it might be to collect the information to prove your point, I don’t know, it depends on a case-by-case basis.

But it’s -- you know, there still is an opportunity to look at some of these. And I think that’s probably something that’s less likely for oil sands and, you know, Mike might agree that that’s pretty much if you're mining down in the ground, yeah, it's probably high-carbon intensity. Or if you're sticking it through an upgrader, using lots of energy to upgrade to something, yeah, that's a high-carbon intensity crude oil.

But something from a flaring country that might be close to the standard, and recognizing that flaring intensity calculations are all of the crude oil production, you know, is the denominator, and the flaring amount estimated is the numerator, and then you get an intensity for all of the crude oil.

Well, all of the crude oil being produced is not being produced equally, with the same amount of associated gas being burned. There could be regions that don't do that, collect it, pump it back in.

So if you can demonstrate that, that that crude that you're getting from that part of the country has not had flaring, then you can have that recharacterized as a non-HICO crude.

Enhanced oil recovery, thermal enhanced oil recovery is probably something that will be a HICO, although I imagine it could possibly depend on the amount of cogeneration that may be occurring, I'm not sure about that.

So these are the categories and these are what we looked to tag, these certain crudes.

Just a quick point of reference that California does in fact use thermally enhanced oil recovery to a rather significant amount. But this is a group of crude oil production or category that is, I guess grandfathered, for lack of a better phrase.

The 2006 baseline crude is the California crudes and then a list of foreign source crudes imported at that time.

So, this is just an update of what we have in the draft report. The 2009 data is now just coming in for this. I know it’s 2011, but I guess there was a lag over at Department of Oil, and Gas, and Geothermal Resources.

So, it’s about 51 percent now, in 2009, and that’s almost the record level. So, it’s been going up recently but, as you can see, there have been cycles that have occurred in California.

But, certainly, the older fields in California do require some secondary oil recovery and thermally enhanced oil recovery continues to be a large element of California’s production.

VICE CHAIRPERSON BOYD: Gordon?

MR. SCHREMP: Yes.

VICE CHAIRPERSON BOYD: TEOR, thermally enhanced versus CO2 injection, if somebody substituted CO2 for their present use of steam, is anybody calculated -- is there a net benefit with regard to the HICO analysis and the CI score, et cetera, et cetera?

MR. SCHREMP: Well, I think at this time the crude oils are really sort of in two -- they'll be in three camps, I suppose. One is non-HICO and everybody is pretty clear.

VICE CHAIRPERSON BOYD: Right.

MR. SCHREMP: Another is clearly HICO, like oil sand mining. And then there's the potential ones that could be.

So, it's really not a quantification of what its carb intensity might be for a particular flavor of crude oil, whereby you would take in some of these other considerations going on.

But if, in fact, you're injecting CO2 as a means of trying to do a secondary extraction of oil, that's not a potential HICO crude oil production activity, certainly.

Now, if your question is I'm actually capturing CO2, I'm injecting it, sequestering it, as Mike mentioned before, is that something that could get credit. So, I don't know -- he's nodding his head yes, but if there's a better explanation.

VICE CHAIRPERSON BOYD: I don’t want to protract this but it’s in --

MR. WAUGH: Real quickly, the LCFS explicitly allows a high carbon intensity crude oil to use innovative techniques, such as CCS, to reduce its CI and become a non-HICO.

VICE CHAIRPERSON BOYD: And as I understand it, actually CO2 more drive more oil out of the ground than steam would, too, so anyway.

MR. WAUGH: Sounds like a win/win.

MR. SCHREMP: Thank you, Mike.

So, the results of the screening of the 248 MCONs are this, and this is a county if you will, just numbers.

And so, as Mike pointed our earlier, nearly 80 percent are pass. The others in the potential category, you can see the different reasons. Most because they fail the flaring screen, the initial flaring screen. And that’s the 51 received a fail and 45 were because they were over this flaring intensity limit of 10 cubic meters per barrel.

So, there’s some that fail a couple of different screens and so that’s why you won’t add these numbers up, they won’t exactly equal, so there’s double failures in here. But mostly it’s because of flaring.

Now, all crude oil production of a certain flavor are not equal in terms of their volume, and so when you volume weight it you see that there is a slightly higher percentage of them that are potential HICOs.

And so the number of non-HICO now drops to 74. So it’s like -- as like Mike said earlier, it’s about you know, three-quarters are good and one quarter is potential.

So, California does, has used potential high-carbon crude oil. And in 2010, this is an illustration of source countries and potential HICO. And you see they add up to nearly 17 percent and since imports of foreign oil are about half of what we use, about eight percent of the total crude oil being used in 2010, by refiners, we believe there’s a potential high-carbon intensity crude oils that, if continued to be used would have to offset those incremental carbon deficits, especially if they want to retain any credits they may have used for use of renewable fuels under the LCFS.

So, we think the likelihood that refiners will pursue this would be not high, to give it a ranking. Very unlikely because it’s quite difficult, even a modest eight percent offset, the carbon deficit is quite high in this example I gave, and even a lower two percent it’s difficult to offset.

So, we think that refiners will, instead, elect to use alternative crude oils and then that will have, you know, some impact on their operations.

With regard to potential changes outside of California, by crude oil producers, solely in reaction to the HICO provisions, it’s unlikely. And that’s because California, the market for California is small relative to other markets that they can sell to.

And, certainly, none of these producers are what I call captured; they’re not in a location where they can only sell into California. If, in fact, the high-carbon intensity crude oil provision was applied in the State, then as you see a great deal of TEOR production that they -- some of them could have been captured and some of them may be able to get their product to market and exported, and but that’s not the case. So, we think that’s unlikely.

And just want to point out that activity to reduce carbon footprints outside of California and these other countries are done for economic reasons, a high enough return on investment, and these are -- there’s various types of projects, but they’re done mainly to reduce operating costs or if they can collect the gas they’re flaring, and have another market, a higher value and that pays for the investment.

And the final point is that there are -- there are fees imposed, carbon fees, and this is the case in Canada, and so you can see a reaction by lowering the carbon footprint.

So, a conclusion is that certainly we think that the access to crude oil globally will be somewhat restricted and then there will be, you know, an impact, but we don't think it will be too the point where refinery operations will have to be significantly altered, but they will incur a higher cost of operation.

So, what is that cost? Well, we didn't quantify that as part of this work, but you need to know some of the items I have listed here.

And shuffling has been mentioned. And I think maybe Skip is going to talk a little bit about that. But you want to know where the replacement crude originated from and what those differences, relative differences are.

Now, you could look at, say, Canadian crude coming here and that's fairly close, and so an alternative crude to that is probably not going to be the same distance or closer because that's almost as close as you can get.

So, shuffling is a legitimate issue but, you know, quantifying that into what degree, you know, we did not -- staff did not do that.

And the final point is, as you mentioned this morning, Commissioner Boyd, energy security. That's a very good question, but certainly the challenge is what kind of framework and structure do you put around to get that kind of ranking of, you know, good countries and bad countries, good sources and bad sources.

So, that's a good question and so we're certainly -- staff's very interested in taking some additional, you know, direction and feedback on that issue. And that's it.

VICE CHAIRPERSON BOYD: Good conclusion slide there. All right, thanks Gordon.

I'm going to -- a quick comment, because I don't want to keep people any longer than I have to. The question about CO2, I want to leave you with another thought because I won't be sitting here this time next time, or next time you do another IEPR, or what have you. But I'm just trying to bring a bunch of subjects together and one of them is the fact that, you know, we have been talking for a couple years now to utilities about someday AB 32's going to come home to use natural gas burning generators, and you're going to have to do something about it, and you might think about capturing your CO_2.

And to the extent that they're even barely close to California oil fields, somebody might consider the thought of using CO_2 instead of burning gas to create heat to make steam, to inject in the ground. And if I'm not mistaken, I understand that the chemistry involved actually drives more crude oil out of the pore space and they might actually get a net increase.

So, some people might start thinking in the future of something like that in lieu of as much crude shuffling as you talk about because there may be an incremental improvement in their HICO score, if I can use a crude analogy. Pardon the pun.

In any event it's just something to think about for the future because I won't be here to pound it into your heads anymore.

So, okay, enough said. Any questions for Gordon?

Then we should move on to our very patient speaker, Skip's been sitting there, like the rest of us, all day, and we did commit to stay to the bitter end.

MR. YORK: Hi, I'm Skip York, I'm a Vice President in Downstream Consulting for Wood MacKensie Consultants.

What I'm going to do is use the charts here, but

I’m going to deviate a little bit and try to qualitatively talk about some of the issues that have come up about today.

We, at Wood MacKensie, take a little bit different view because we see things globally, as a global firm. So, we work carbon cost issues, not just in California, but we’re also doing similar analysis in other parts of the world. And that also means that, predominantly, we’re doing a lot of -- a fair amount of work in Europe.

So what I’ll do is at certain points I’ll sort of compare and contrast the work that we’ve done around how the HICO or how carbon oil, carbon intensity under the LCFS and sort of draw some our conclusions for the State of California, but then also contrast them with some areas.

One of the things thing I want to do is that we agree with the CEC on the point that when you look at things from a global basis it’s going to be very challenging for a market, as small as California, and I know that may sound a little bit strange for people who live in California, but on a global basis it’s going to be difficult for a market as small as California to have a material impact on how the crude or how the global dynamics for the pricing and movements of crude flow.

There will be -- when we get to the crude shuffling point, there will be a point where we will pause and actually talk through what the HICO implications are of crude shuffling and some of the strategic risks that the HICO provision as proposed, and not the final rule, but as sort of what's been laid out there what, potentially, you could be selling yourself into and it's just a risk that needs to be thought of and addressed as we go through it.

So, with that as an introduction, what we do want to do is when we look at crude oil markets on a global basis, Gordon made a very good point that as long as the crude producer, as long as the well head does not have to comply with the LCFS and has the ability to go someplace else, there is an economic incentive for them to choose to push themselves into another market.

And it's not just the LCFS, that's true of any -- that's true of any restriction that you put on the global crude oil market.

Now, in particular, when you think about what's happening in California with the decline in California production and the decline in Alaskan production, that means that every makeup barrel that is -- every barrel that is brought in to make up a barrel of lost production in California or Alaska is coming in off of the water, and that means it's being exposed to the global crude markets.

And, therefore, as Gordon used it, it's not a captured barrel, it's a barrel that will flow to its best economic value.

And that's where we kind of say the sub-point here is that one of the things that needs to be considered is the increased carbon emissions from the crude oil shuffling, as tankers -- as the HICO provision will literally encourage tankers or you're going to create an incentive for tankers to pass each other on the open seas, with high-intensity crudes flowing away from California and low-intensity crudes flowing towards California.

In addition, the California refineries were designed to produce, you know, a heavy, deep conversion sort of crude oil which is what's in decline. The high-intensity crudes tend to be more of your low API, high sulfur, they tend to be the very nonfungible, difficult-to-refine crudes.

And they're going to be replacing them with the lower-intensity crudes, you're reducing the operational efficiency of the California refiners and you're placing that difficult refined crude into more simpler, less complex, less conversion, you know, less efficient refinery somewhere else in the world and that's going to have energy efficiency implications, which means there are carbon emission implications when those high HICO crudes end up wherever they're going to end up.

The other point that we want to do is kind of point that the future is today in the -- although the baseline was defined in 2006, we're going to show how just in the last four years we've seen dramatic changes in how the California crude slate, refining crude slate has changed, and that is just sort of precursor of the shape of things to come.

And then the conclusion then being that the high-carbon crudes, if you deflect them from California, they will still be produced. Because if you think of a world in which we're going from 85 million barrels today of crude oil consumption today, to 90 or 100 million barrels a day of crude oil consumption, the bottom line is the oil sands are coming.

That the global oil market cannot possibly meet growing oil demand, especially in the emerging world, without the development of the -- what we call sort of the extreme sources, such as the Canadian oil sands or the ultra-deep water production.

That production has to come in order -- if we believe that the emerging world is going to pull itself out from being an emerging world and into a developed world, it's going to require more energy. And if that energy takes the form of liquid fuels, then there's no way that that equation can possibly be met without bringing these sort of new sources, or these unconventional crudes on stream.

So, here's just a view of when we define the base year, you know, about 95 percent of the crude slate in 2006 fit the baseline definition. So, in other words, it would be a low-carbon intensity crude oil by definition, as the definition that's been -- the potential definition that's been proposed.

But if you look over the next five years, just through the natural decline in baseline crudes out of California and out of Alaska, that we've sort of seen that those baseline crudes are now less than 80 percent of the California crude slate and they're being made up by one of two ways, either you're going to be importing more barrels from someplace else in the world and those barrels, by definition, were non-baseline crudes, or you're going to be cutting refining runs; which means instead of bringing in an imported barrel of crude, you're going to be bringing in an imported barrel of product in order to satisfy California petroleum demand.

Now, this is where we're going to slow down for a bit and kind of talk about the security and supply implication. So, if you sort of think in a very simple term, what the HICO definition does, if you sort of say that we're not going to allow -- you know, that we're going to define sort of like the Canadian oil sands crudes, or heavy production crudes out of Brazil or Columbia, out of Venezuela as being high-intensity crudes, then what you do is you end up putting up a brick wall to those locally-sourced crudes from South America or from Canada.

And at the same time you're going to still have refining crude runs that need to be met and the low-intensity crudes that fit the definition, since the Californian and Alaskan crudes are in decline, you're increasingly pulling barrels of crude, which is the green magnet, away from the low-carbon intensity crude country defined areas, which is largely from the Middle East.

So, here's what has to happen for that barrel to make it to California, when we think about it from an energy supply basis. First of all, just the mere distance of coming from Canada to California, versus from the Middle East to California, the length of distance increases the length of the supply chain. In other words, there's more distance and there's more time for something in the supply chain to go wrong. And that means if the barrel of crude doesn’t show up in time to be refined the way you’d -- at the time that you need it to be refined in order to keep the California market supplied.

But the other thing to note is that -- is two other things. One, that marginal barrel of crude that’s having to come in today, so as you sort of think about that, the baseline crude’s going from 95 percent down to 80 percent, that 15 percent swing from baseline to non-baseline crudes is being met by Middle East barrels.

Now, that Middle East barrel has to come out of the Strait of Hormuz which, at its narrowest point, only allows two tankers to flow.

If it can make it through that without the political uncertainty in the Middle East, if it makes it out of the Strait of Hormuz, it then has to flow past the Straits of Malacca, which is the most pirate intense shipping lane in the entire planet.

If it makes it through the Straits of Malacca, you now have to bid that barrel of crude away from the Asian refining demands in order to make it attractive to land in California.

Now, the reason why that last point is in important is that since the Global recession ended in

2009, more than 100 percent of the growth in oil demand has been in Asia. And the reason why it’s more than 200 percent of demand is that we still have declining oil demand in the developed worlds of Europe, North America, Japan or Australia.

So, the growth market of the world, on an oil demand side, that barrel is going to have to get priced at a point where it will -- the Chinese, or the Singaporean, or the Korean refiner will let that expensive barrel slide by and head on to California, and then it has to cross the Pacific with no mechanical interruptions, or no impact, and land in California just in time to hit the tanks and then go into the refinery.

Now, at the same time, if you’re pricing those low-intensity crudes at a high enough point to pull it out of Asia and into California, you’re also discounting those high-intensity crudes coming out of Canada and coming out of South America, and you’re actually discounting crudes into Asia, so that’s where the crude shuffling goes on.

It happens because the California refiners have to put a high enough price to pull the low-intensity crude out of the Middle East and a big enough of a discount, and you’re discounting the local Canadian crudes, or the nearby Canadian crudes so that they can flow to Asia, and those tankers literally pass each other on the open seas.

Now, while all that's going on, this kind of just goes to Gordon's point and this is just a chart that demonstrates, you know, how you have to kind of move the -- what you have to believe that this policy actually alters world oil demand, world oil production, is that the dark blue line at the bottom of the chart is California oil demand and the light blue is demand everywhere else, which is somewhere in the neighborhood of 85 million barrels a day and growing.

So, as you move through time, as we move going forward, California actually becomes a smaller percentage of the world oil demand and so its influence to -- its ability to influence the well head economics in places like either Canada, or the Middle East shrinks in proportion to its -- to the size of its -- to where it fits in the global market.

Now, that leads us to the final chart. So, if you're in a world where that marginal barrel comes from a water borne barrel, and that water borne crude barrel can flow anywhere in the world, once it hits a ship it can land on any refinery anywhere, the producer has the ability to avoid the policy implications of the LCFS through HICO.

And even if it’s a low-intensity crude, it has the ability to price itself into whatever market is going to offer it the most attractive price.

On the other hand, if you’re a refiner, the HICO definition restricts the number of crudes that are available to you, and by restricting the number of crudes that are available to you, you reduce your ability to either influence the price and attract crudes, or you also reduce your ability to diversify your supply, which sort of says that the HICO -- when you define HICO, what you need to be looking for is something that avoids the crude shuffling because that’s a net increase in carbon emissions, greenhouse gas emissions. And you also want to be looking for something that doesn’t adversely impacting your security of supply by unduly restricting the portfolio of crudes that you can select from.

And so that’s kind of the essence of what we wanted to talk about today was that, you know, we largely agree with what the CEC has put in their draft report, that the California market has -- the size of the California market makes it difficult for them to influence policy in other parts of the world.

And that if you’re not careful with how you define your policies, you’re going to end up putting yourself at -- you actually take on taking energy supply risk with no benefit, with no direct benefit, and possibly with a carbon cost due to the crude shuffling.

And that’s just what we’d -- the comments that we have is that as you’re finalizing the policy that you sort of be thinking about ways to mitigate those potential security supply risks and those carbon emission risks. And that’s the extent of my comments.

VICE CHAIRPERSON BOYD: Thank you. In your analysis have you ever looked at the issue of at what point California crude oil leaves California instead of being processed in California?

MR. YORK: Well, we didn’t look at it in this analysis, but there is -- I guess there’s good news, in that there is an Executive Order signed back by the President -- there’s a Presidential Executive Order, signed back in 1982, which prohibits the export of U.S. crude. And there’s only -- without a Presidential exemption, and there’s only two crude oils that have that exemption today, one of which is ANS.

So, absent a Presidential waiver, California crudes are captive to California refiners, or to U.S. refineries --

VICE CHAIRPERSON BOYD: Right, to the U.S.

MR. YORK: -- and that by their logistics they’ll be captive to California.

VICE CHAIRPERSON BOYD: Any other questions from folks here? Yes?

MR. STEVENSON: Dwight Stevenson, Tesoro. I wanted to amplify a little bit on what Skip had to say, and thank you for sticking it out so long, Commissioner Peterman.

VICE CHAIRPERSON BOYD: Yeah, she has a meeting in the Governor’s --

COMMISSIONER PETERMAN: I’ll get a recap of your question.

VICE CHAIRPERSON BOYD: There’s a meeting with the Governor’s staff that is rather important.

MR. STEVENSON: Okay. The point I want to make is that when you’re changing the incremental crude market, the incremental crude that’s coming into a refinery, and instead of having something that’s lower priced from Canada, and having to buy something that’s more expensive from the Arab Gulf, you’re going to go look for other alternatives, first, and what happens is that all of those other alternatives get bit up, and as a final resort you go to the Arab Gulf.

So, this is not just on the high-carbon crude, this impact of a higher price is not just on those 10, 20, 30 percent potential high-carbon crudes, we don’t know how many, it’s the entire crude market.

Would you agree with that?

MR. YORK: Yeah, I would agree that once you start -- once you start restricting the crudes that you’re going to look at and you start bidding against those then, you know, the -- it’s not just one refiner in California that will be bidding into that market, it will be every refiner in California that bids into it.

And that crude could have more value to some other refiner than it has to you and that starts another bidding, the bidding game as well.

And so the market, it’s a bit of the Genie gets out of the bottle, once you start it it’s -- the crude -- the crude markets will find a new equilibrium, but that new equilibrium could have unintended consequences in terms of the cost of supply for petroleum products to California and the security of supply of the volume into the California markets.

VICE CHAIRPERSON BOYD: Other questions, comments?

Okay, thank you, Skip.

MR. YORK: Yeah.

VICE CHAIRPERSON BOYD: Now, public comment, Gina is waiting anxiously.

MS. GREY: Gina Grey, from WSPA, again. And I apologize, but these are -- we have some prepared comments and I will try and keep these short, but the WSPA organization did feel that we wanted to make some comments at the end to try and summarize our general view of the Transportation Report at this point in time.

First of all, congratulations are in order because we actually, as WSPA, want to thank and recognize the tremendous effort by staff to improve the IEPR Transportation Report.

And I know I've stood in front of you many times, Commissioner Boyd, and had a long litany of complaints and issues with the report, but we actually have seen a seed change, I think, in improvement in the report. It's very much improved from what was produced in the past.

There's a greater understanding and recognition in the report of the complexities of the transportation fuels arena, and the considerations and challenges inherent in trying to transition to a wholly different fuel system in a rapid time frame.

What appears to be one of the main themes, however, is the high level of uncertainty in what lies ahead, particularly with respect of future contributions of various renewable and alternative transportation fuels and technologies.

There are, for example, questions about the adequacy of alternative fuel supply, the adequacy of the infrastructure and the technical, and environmental questions still to be addressed.

Overlaid on this are the prevailing issues of whether the fuels, the vehicles and the consumers will nicely match up.

In contract to historical IEPR documents that painted a very optimistic picture of the alternative fuel future contributions and the rapid demise of the petroleum industry, this document appears far more balanced. And I think we heard that from other people today that they sort of characterized it as a more balanced report.

One aspect we did find disappointing, however, was the lack of a next step analysis, and I think I heard this from John Braeutigam earlier, that would take much of the information obtained over these many months of staff work and provide what is required by the enacting Bowen Bill, which is to develop policies for the IEPR.

The report identifies many significant problems, but normally doesn't go the next step in providing recommended solutions or changes to State policy, for example.

And we actually took an example from the report, which is relative to E85. We see in the report that staff projects E85 infrastructure costs, alone, will be from $3.1 billion to $101.8 billion, and that’s if you add up all of the components out to 2030. Which, they say, on a per-station basis for dispensers are many times greater than the total annual profits of a typical retail station.

the report also says the number of FFEs needed is needed to increase from 450,000 in 2010 to 5 million by 2030 to enable an adequate market for volumes of 85 needed to meet RFS2.

So, the reader is left with many questions. How is all of this going to happen? Or, more importantly, does the CEC believe this will realistically happen? What will be the impact on the State’s economy and the consumers? What needs to be done or undone in order to accomplish this?

So, there’s the types of questions that typically go through your head as you’re reading this report.

Now, we do note an exception to this lack of sort of next step, which was on page 88, where the staff recommends the EPA consider convening a forum to ascertain the primary causes for a lack of progress regarding the growth of cellulosic biofuel production capacity under the RFS2, along with a consideration of modifications to the program.

This is an example of what we'd like to see more of in the report.

So, WSPA would like this report to provide policy recommendations as input to the overall IEPR. And I think that's what we have said in the past, too, that even if a lot of these issues and comments are incorporated in this Transportation Report, we typically don't end up seeing it in the actual IEPR.

So for policymakers, who are looking at just the IEPR document, often those key issues are missing.

In our March set of IEPR comments we stated, "The CEC does not appear to be actively and urgently working to chart a specific strategy that will deal with a very tight demand supply outlook embedded in the Commission's Transportation Fuels Forecast."

So, this comment and our concern still stands relative to that March comment.

We would like to request that certain main issues be highlighted in the main IEPR document, so policymakers are appropriate forewarned.

Some of the issues and we'll probably have more in our written comments, that we'd like to have included in the IEPR are, and first of all, this first one may strike you cold because we were going to say this earlier in the day, but time was short, which is the need for CEC to conduct the transportation fuels analysis on an annual, rather than a biannual basis.

I don’t see staff saying rah-rah over there.

VICE CHAIRPERSON BOYD: Do you have a revenue source to get the added staff that --

MS. GREY: Yeah, I noticed that in the report, too, about the resources.

Since many of the fuels were not dealt with in detail in the report and there are several sections that talk about why that was, but it also says that this is ongoing work that will be completed at some point in time, but it’s not explicit as to when all that will be completed.

So, we just, again, would like to suggest that this be an annual report, particularly at this point in time when it seems -- you know, with the LCFS, with the RFS2, a lot of these programs in play.

It seems that the transportation fuels arena in the past, I know we’ve said this a lot, has received a bit of short shrift in the IEPR context where electricity is, annually, but transportation fuels is not. So, it’s consistent with what we’ve said before.

VICE CHAIRPERSON BOYD: Don't you know what CEC stands for? The "California Electricity Commission."

MS. GREY: The "Electricity Commission" right.

(Laughter)

MS. GREY: All right, second bullet, which we talked about earlier today and I mentioned, the need for a CEC reporting mechanism for alternative fuels.

Thirdly, the need to include a detailed analysis of the vehicle and consumer side of the equation and I think it was kind of interesting this morning when we were talking about sort of the vehicle attributes, and the consumers were kind of in there. But when you look at the back end of the document there is, I think, a couple of paragraphs and three or four tables that deal with the vehicle side of this whole thing. And I think, again, we're always saying the three-legged stool, vehicle, fuel, consumer.

And, unfortunately, because this is, as I know, transportation fuels, but very important need to include the vehicle side in probably a more prominent position in the report.

And the next bullet was the need to highlight the possible consequences of the LCFS program including the crude differentiation approach.

And the need to continue to support the

petroleum industry in terms of expanded crude production, marine and other infrastructure.

And I think a lot of that goes to our continual mantra which is, fine, if the State wants to continue with alternative and renewable view focus in terms of transition, but don’t forget about the petroleum side as well, and the fact that just making sure that that side of the equation doesn’t have a hindrance in terms of our ongoing energy supply while the transition takes place is equally important.

And I think there are several things mentioned in this transportation report, like the marine infrastructure, that, again, need to be highlighted in the IEPR.

And then, lastly, the need to translate this report for use by the AB 118 effort and to determine if revisions are needed to the AB 118 program.

And I think by that we just mean that, again, making sure that whatever comes out in this report is recognized and understood, and the AB 118 Advisory Committee is educated on maybe some of the elements of that, because not everyone reads 270 plus pages.

And, plus, just there have been some discussions recently about whether or not the AB 118 program, in terms of how it’s constructed, what the rules of the game are, et cetera, are appropriate as we move forward. And maybe there are some revisions that may be necessary in that, and that’s probably legislatively driven and you need to change that, but that was just another thought on our part.

So, those were just some of the thoughts that we had in terms of what needs to be reflected in the IEPR in addition to what’s in this Transportation Fuels Report. Thank you.

VICE CHAIRPERSON BOYD: Thank you, Gina.

Any other public comments? Any questions out there in -- staff, do you have any concluding wrap-up comments you’d like to make?

MR. PAGE: Jim Page, of the Energy Commission. Just that we have an IEPR schedule that’s actually fairly tight, where all of these -- all this work that we’re proposing or has been proposed probably will not -- will almost certainly make it into the IEPR given the short lead time.

Our final report we have no time, there is no date at which our final report has to be completed.

And I would like to emphasize, too, that this, while not maybe an annual process, is a continuous and ongoing process for staff to learn, to understand, to incorporate, to get information, to learn about new data sources, to hear ideas about how that can be incorporated into analysis, new problems that come up, issues people have with our work. This is ongoing, it will continue long after I'm gone.

So, that's really all I want to say.

VICE CHAIRPERSON BOYD: Are you retiring, too?

MR. PAGE: Don't tempt me. Yes, that's really all I want to say is that we do have a short lead time to contribute to the IEPR, so not all of the work that's been proposed can get done in that time frame.

But, again, we do have more time to do the final report. Whether we can do more workshops, we would like to look into that possibility. Obviously, there's a whole slew of questions that have been raised and we have not -- we're not close to the answers for all of them.

But for the IEPR purposes, it comes every two years and we just -- we can't stop it. Whether we're ready or not, we have to contribute by a certain date and that's the constraint that we will always have.

And I would also like to thank you all very much for staying this long, this late and contributing so much. It's really a pleasure, I really appreciate it.

VICE CHAIRPERSON BOYD: Thank you, Jim. Well, let me just say that I, too, appreciate, one, the work of the staff, the tremendous amount of work that has gone into that. And only I, in particular, some of us know that we have fewer staff now than we've ever had in the past, in light of these tough times, so they've taken on a big task and they have worked very hard to bring it where it is. And the fact that some people like it better than they used to like it is indicative of, I think, the hard work that has gone on.

Commissioner Peterman, who did have a 5:00 o'clock appointment in the Governor's Office, and put him off until 5:25, whispered in my ear, just before she left, that this is one of the best workshops she's attended and she's only been here roughly a year, but carries a workload on the renewables area. Although, I share the Committee with her, she's the Chair, I let her do the heavy stuff.

So, it was impressive to all of us and we appreciate your input.

There is a desire, continuously, to shrink the size of the IEPR down because it's so big that nobody -- I mean we struggle to get people to pay attention to it.

Jim's comments about, you know, the subordinate report, we have more time to finish it up and we have been talking about having more workshops, just some way to have a continuing dialogue on the subject.

And with the passage of time and events, and what have you, a lot of the people have learned about, you know, the status of the economy, what you can and can’t do, things not realized. The cellulosic ethanol example is one good one of what people predicted the future would be and it didn’t turn out that way. And I’ve had to wait a long time for the second coming of batteries in electric cars, et cetera, et cetera.

So, again, thank you all for your input, we’ll work with it, we’ll work on it, with work with the staff, the Commissioner and I, in helping them craft the final version of this report and, more importantly, craft what will go into the IEPR in the limited page space we’ve been allocated, I’m sure.

So, anyway, thank you all, have a good weekend, and appreciate the work you all put into this effort. It’s been very enjoyable, very educational. Thank you and good night.

(Thereupon, the Workshop was adjourned at 5:35 p.m.)

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